OPEN MEETING COVER SHEET

COMMISSION STAFF MEMO AND PROPOSED ORDER APPROVING NODAL PROTOCOLS

MEETING DATE:	July 15, 2021
DATE DELIVERED:	July 14, 2021
AGENDA ITEM NO.:	26
CAPTION:	Project No. 52307 – Review of Rules Adopted by the Independent Organization in Calendar Year 2021
DESCRIPTION:	Discussion and possible action.

Distribution List:
- Commissioners' Offices
- Journeay, Stephen
- Agenda
- Zerwas, Rebecca
- Smeltzer, David

Public Utility Commission of Texas

Memorandum

TO: Chairman Peter Lake
Commissioner Will McAdams
Commissioner Lori Cobos

FROM: Rebecca Zerwas, Market Analysis

DATE: July 14, 2021

RE: July 15, 2021 Open Meeting – Item No. 26

Project No. 52307 – *Review of Rules Adopted by the Independent Organization in Calendar Year 2021 (Discussion and possible action)*

Senate Bill (SB) 2 (87th Legislature, Regular Session) requires both the Commission and the Electric Reliability Council of Texas (ERCOT) to establish processes for Commission approval of any rules or protocols adopted under authority delegated from the Commission to the independent organization. Commission Staff has opened Project No. 52307, *Review of Rules Adopted by the Independent Organization in Calendar Year 2021*, to facilitate Commission review and approval of the rules adopted through the ERCOT stakeholder process since SB2 was signed into effect on June 8, 2021.

Attached for your consideration are the following Nodal Protocol Revision Requests (NPRRs) and Other Binding Document Revision Request (OBDRR) as approved by the ERCOT Board of Directors at its June 28, 2021 meeting:

- NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap;
- NPRR1081, Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed; and
- OBDRR030, Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap.

Included for your review are the Board Report and ERCOT Impact Analysis for each revision request. Also included are comments filed by Staff at ERCOT in support of NPRR1080 and

NPRR1081. These documents are intended to provide a market impact statement describing the revisions. Staff recommends approval of NPRR1080, NPRR1081, OBDRR030.

Additionally, Staff requests consideration of OBDRR031, Change Non-Spinning Reserve Service Deployment, as approved by the Technical Advisory Committee (TAC) at its June 30, 2021 meeting. Included for your review are the TAC Report and ERCOT Impact Analysis. Staff recommends approval of OBDRR031 in support of ERCOT's efforts to enhance grid reliability and reduce the likelihood of entering Emergency Conditions.

Staff anticipates further conversation regarding the revision request approval process as part of a rulemaking to consider ERCOT governance. Currently, Staff is planning on bringing a discussion draft forward for consideration in August and will continue to work with ERCOT on amendments to the revision request approval process to implement SB2.

Please find attached a proposed order for your consideration consistent with Staff's recommendation in this memo.

PROJECT NO. 52307

REVIEW OF RULES ADOPTED BY THE INDEPENDENT ORGANIZATION IN CALENDAR YEAR 2021	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

PROPOSED ORDER APPROVING NODAL PROTOCOLS

This Order addresses revisions to two Electric Reliability Council of Texas Nodal Protocols and revisions to two Other Binding Documents. The Commission approves the revisions and the accompanying market impact statements.

The ERCOT board of directors approved Nodal Protocol Revision Request (NPRR) 1080, *Limiting Ancillary Service Price to System-Wide Offer Cap*, NPRR 1081, *Revision to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed*, and Other Binding Document Revision Request (OBDRR) 030, related to NPRR 1080, *Limiting Ancillary Service Price to System-Wide Offer Cap*, at its meeting on June 28,2021. In addition, the Technical Advisory Committee approved OBDRR 031, *Change Non-Spinning Reserve Service Deployment*, at its meeting on June 30, 2021.

NPRR 1080 revised ERCOT Nodal Protocol § 4.5.1, *DAM Clearing Process*, and § 6.4.9.2.2, *SASM Clearing Process*. NPRR 1081 revised ERCOT Nodal Protocol § 6.5.7.3.1, *Determination of Real-time On-line Reliability Deployment Price Adder*.

OBDRR 030 revised *Methodology for Setting Maximum Shadow prices for Network and Power Balance Constraints*, Appendix 2, *Day-ahead market Optimization Control Parameters* and supports NPRR 1080. OBDRR 31 revised the *Non-spinning Reserve Service Deployment and Recall Procedure*, §§ 2 and 3 and supports ERCOT Nodal Protocol § 6.5.7.6.2.3, Non-spinning Reserve Service Deployment.

Effective June 8, 2021, rules adopted by ERCOT under delegated authority from the commission are subject to commission oversight and review and may not take effect before receiving commission approval.[1] Further, also effective June 8, ERCOT's process for adopting new protocols or revisions to existing protocols must require that new or revised protocols may

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[1] PURA § 39.151(d); *see also*, *id.* § 39.151(g-1) ERCOT's protocols must be approved by the commission.

not take effect until the commission approves a market impact statement describing the new or revised protocols.[2]

Commission Staff filed a memorandum on July 13, 2021 related to these revisions in which it recommends that the Commission approve the revisions to the Nodal Protocols and to the Other Binding Documents. Attached to Commission Staff's memorandum were supporting ERCOT documents, which constitute the market impact analysis.

The Commission finds that these revisions are necessary for the proper functioning of the ERCOT market as demonstrated by the supporting material and the Commission issues the following orders:

1. The Commission approves NPRR 1080 and accompanying market impact statement.
2. The Commission approves NPRR 1081 and accompanying market impact statement.
3. The Commission approves OBDRR 030 and accompanying market impact statement.
4. The Commission approves OBDRR 031 and accompanying market impact statement.

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[2] PURA § 39.151(g-6).

Signed at Austin, Texas the ______ day of July 2021.

PUBLIC UTILITY COMMISSION OF TEXAS

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PETER M. LAKE, CHAIRMAN

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WILL MCADAMS, COMMISSIONER

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LORI COBOS, COMMISSIONER

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Board Report

NPRR Number	1080	**NPRR Title**	**Limiting Ancillary Service Price to System-Wide Offer Cap**
Date of Decision	June 28, 2021		
Action	Approved		
Timeline	Urgent – Urgent status is necessary to limit Ancillary Service prices to the effective System-Wide Offer Cap (SWCAP) as quickly as possible.		
Effective Date	July 1, 2021		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	4.5.1, DAM Clearing Process, 6.4.9.2.2, SASM Clearing Process		
Related Documents Requiring Revision/Related Revision Requests	Other Binding Document Revision Request (OBDRR) 030, Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap		
Revision Description	This Nodal Protocol Revision Request (NPRR) limits the Ancillary Service Market Clearing Prices for Capacity (MCPCs) to the effective SWCAP. This limitation will be achieved by reducing the Ancillary Service penalty factors used in Day-Ahead Market (DAM) and Supplemental Ancillary Services Market (SASM) to values equal to or immediately below the SWCAP.		
Reason for Revision	☐ 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	During the February 2021 extreme winter weather event, Ancillary Service MCPCs reached record highs well above the $9,000/MW per hour SWCAP in effect at the time. This occurred for two reasons. First, the DAM clearing algorithm considers Resources' opportunity cost of providing other services that they would otherwise be able to provide, and the opportunity costs were higher than had previously		

Board Report

	been encountered. Second, the Ancillary Service penalty factors for not awarding Ancillary Service are significantly higher than the SWCAP, so the DAM algorithm was willing to clear the Ancillary Service Offers despite the resulting MCPCs being above the SWCAP. In this NPRR and the accompanying OBDRR030, ERCOT and the Independent Market Monitor (IMM) propose to limit Ancillary Service MCPCs to the SWCAP. This limitation is achieved by reducing the Ancillary Service penalty factors to values equal to or immediately below the SWCAP, which will prevent Ancillary Service Shadow Prices, and in turn, MCPCs, from exceeding the SWCAP. The changes proposed in this NPRR are consistent with economic market design principles Since Ancillary Service is procured to reduce the probability of losing Load, such principles dictate that the value of reserves should not exceed the Value of Lost Load (VOLL), which is equal to the SWCAP. However, reducing Ancillary Service penalty factors to the SWCAP increases the likelihood of Ancillary Service insufficiency during tight conditions because the DAM algorithm will have the option of forgoing an Ancillary Service Offer at a lower cost
Credit Work Group Review	See 6/16/21 Credit WG comments
PRS Decision	On 6/10/21, PRS voted via roll call to grant NPRR1080 Urgent status. There was one opposing vote from the Independent Generator (Exelon) Market Segment PRS then voted via roll call to recommend approval of NPRR1080 as revised by PRS, and to forward to TAC NPRR1080 and the Impact Analysis with a recommended effective date of upon ERCOT Board approval. There were four abstentions from the Consumer (Occidental Chemical), Cooperative (STEC), Independent Generator (Luminant), and Independent Power Marketer (IPM) (Tenaska) Market Segments. All Market Segments participated in both votes
Summary of PRS Discussion	On 6/10/21, the sponsors provided an overview of NPRR1080, the Impact Analysis, and the request for Urgent status. Participants discussed the mechanics of NPRR1080's changes, its implementation timeline, and proposed desktop edits to NPRR1080's title Some participants questioned the capping of Ancillary Service prices as an out-of-market action which may disincentivize Resources to provide Ancillary Services. The sponsors reiterated that this change is already contemplated in the ERCOT Board-approved Real-Time Co-Optimization (RTC) NPRRs, and NPRR1080 merely accelerates implementation of this component.

Board Report

TAC Decision	On 6/23/21, TAC voted via roll call to recommend approval of NPRR1080 as recommended by PRS in the 6/10/21 PRS Report with a recommended effective date of July 1, 2021. There were three abstentions from the Cooperative (STEC) and Independent Generator (2) (Luminant and Calpine) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/23/21, participants reviewed comments filed for NPRR1080. Some participants questioned the capping of Ancillary Service prices as an out-of-market action which may disincentivize Resources to provide Ancillary Services, and expressed concern that the changes within NPRR1080 may be misaligned with Public Utility Commission of Texas (PUCT) rules regarding Ancillary Services.
ERCOT Opinion	ERCOT supports approval of NPRR1080.
Board Decision	On 6/28/21, the ERCOT Board approved NPRR1080 as recommended by TAC in the 6/23/21 TAC Report.

Sponsor	
Name	Kenan Ögelman / Carrie Bivens
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Company	ERCOT / Potomac Economics - ERCOT IMM
Phone Number	512-248-6707 / 512-879-7971
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
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Phone Number	512-248-6464

Comments Received	
Comment Author	**Comment Summary**
Payless Power 060921	Highlighted recent changes to the Public Utility Regulatory Act (PURA) and pending PUCT rulemakings which would override the changes proposed by NPRR1080

Board Report

Credit WG 061621	Endorsed NPRR1080 noting positive credit impacts as it better aligns pricing outcomes with market expectations, and the current credit calculations take into account the changes of this NPRR
Hunt Energy Network 062221	Expressed support for NPRR1080 as a short-term solution, but urged TAC and its subcommittees to investigate several related items in pursuit of a long-term solution
PUCT Staff 062221	Endorsed NPRR1080 as submitted

Market Rules Notes

Please note that the following NPRR(s) also propose revisions to the following section(s):

- NPRR981, Day-Ahead Market Price Correction Process
  - Section 4.5.1

Proposed Protocol Language Revision

4.5.1 *DAM Clearing Process*

Commented [CP1]: Please note NPRR981 also proposes revisions to this section

(1) At 1000 in the Day-Ahead, ERCOT shall start the Day-Ahead Market (DAM) clearing process. If the processing of DAM bids and offers after 0900 is significantly delayed or impacted by a failure of ERCOT software or systems that directly impacts the DAM, ERCOT shall post a Notice as soon as practicable on the ERCOT website, in accordance with paragraph (1) of Section 4.1.2, Day-Ahead Process and Timing Deviations, extending the start time of the execution of the DAM clearing process by an amount of time at least as long as the duration of the processing delay plus ten minutes. In no event shall the extension exceed more than one hour from when the processing delay is resolved.

(2) ERCOT shall complete a Day-Ahead Simultaneous Feasibility Test (SFT). This test uses the Day-Ahead Updated Network Model topology and evaluates all Congestion Revenue Rights (CRRs) for feasibility to determine hourly oversold quantities.

(3) The purpose of the DAM is to economically and simultaneously clear offers and bids described in Section 4.4, Inputs into DAM and Other Trades.

(4) The DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to security and other constraints, and ERCOT Ancillary Service procurement requirements.

(a) The bid-based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation bids.

(b) The offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of any Resource that submitted a Three-Part Supply Offer, DAM Energy-Only Offers and Ancillary Service Offers.

(c) Security constraints specified to prevent DAM solutions that would overload the elements of the ERCOT Transmission Grid include the following:

(i) Transmission constraints – transfer limits on energy flows through the ERCOT Transmission Grid, e.g., thermal or stability limits. These limits must be satisfied by the intact network and for certain specified contingencies. These constraints may represent.

(A) Thermal constraints – protect Transmission Facilities against thermal overload.

(B) Generic constraints – protect the ERCOT Transmission Grid against transient instability, dynamic stability or voltage collapse.

(C) Power flow constraints – the energy balance at required Electrical Buses in the ERCOT Transmission Grid must be maintained.

(ii) Resource constraints – the physical and security limits on Resources that submit Three-Part Supply Offers:

(A) Resource output constraints – the Low Sustained Limit (LSL) and High Sustained Limit (HSL) of each Resource; and

(B) Resource operational constraints – includes minimum run time, minimum down time, and configuration constraints.

(iii) Other constraints –

(A) Linked offers – the DAM may not select any one part of that Resource capacity to provide more than one Ancillary Service or to provide both energy and an Ancillary Service in the same Operating Hour. The DAM may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service or energy in the same Operating Hour, provided that linked Energy and Off-Line Non-Spinning Reserve (Non-Spin) Ancillary Service Offers are not awarded in the same Operating Hour.

(B) The sum of the awarded Ancillary Service capacities for each Resource must be within the Resource limits specified in the Current Operating Plan (COP) and Section 3.18, Resource Limits in Providing Ancillary Service, and the Resource Parameters as described in Section 3.7, Resource Parameters.

(C) Block Ancillary Service Offers for a Load Resource – blocks will not be cleared unless the entire quantity block can be awarded. Because block Ancillary Service Offers cannot set the Market Clearing Price for Capacity (MCPC), a block Ancillary Service Offer may clear below the Ancillary Service Offer price for that block.

(D) Block DAM Energy Bids, DAM Energy-Only Offers, and PTP Obligation bids – blocks will not be cleared unless the entire time and/or quantity block can be awarded. Because quantity block bids and offers cannot set the Settlement Point Price, a quantity block bid or offer may clear in a manner inconsistent with the bid or offer price for that block.

(E) Combined Cycle Generation Resources – The DAM may commit a Combined Cycle Generation Resource in a time period that includes the last hour of the Operating Day only if that Combined Cycle Generation Resource can transition to a shutdown condition in the DAM Operating Day.

(d) Ancillary Service needs for each Ancillary Service include the needs specified in the Ancillary Service Plan that are not part of the Self-Arranged Ancillary Service Quantity and that must be met from available DAM Ancillary Service Offers while co-optimizing with DAM Energy Offers. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service. See Section 4.5.2, Ancillary Service Insufficiency, for what happens if insufficient Ancillary Service Offers are received in the DAM.

[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]

(4) The DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues, including revenues based on Ancillary Service Demand Curves (ASDCs), minus the offer-based costs over the Operating Day, subject to security and other constraints.

(a) The bid-based revenues include revenues from ASDCs, DAM Energy Bids, bid portions of Energy Bid/Offer Curves, and Point-to-Point (PTP) Obligation bids.

(b) The offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of any Resource that submitted a Three-Part Supply Offer, DAM Energy-Only Offers, offer portions of Energy Bid/Offer Curves, Ancillary Service Only Offers, and Ancillary Service Offers.

(c) Security constraints specified to prevent DAM solutions that would overload the elements of the ERCOT Transmission Grid include the following:

(i) Transmission constraints – transfer limits on energy flows through the ERCOT Transmission Grid, e.g., thermal or stability limits. These limits must be satisfied by the intact network and for certain specified contingencies. These constraints may represent:

(A) Thermal constraints – protect Transmission Facilities against thermal overload.

(B) Generic constraints – protect the ERCOT Transmission Grid against transient instability, dynamic stability or voltage collapse.

(C) Power flow constraints – the energy balance at required Electrical Buses in the ERCOT Transmission Grid must be maintained.

(ii) Resource constraints – the physical and security limits on Resources that submit Three-Part Supply Offers or Energy Bid/Offer Curves:

(A) Resource output constraints – the Low Sustained Limit (LSL) and High Sustained Limit (HSL) of each Resource; and

(B) Resource operational constraints – includes minimum run time, minimum down time, and configuration constraints.

(iii) Other constraints –

(A) Linked offers – the DAM may not select any one part of that Resource capacity to provide more than one Ancillary Service or to provide both energy and an Ancillary Service in the same Operating Hour. The DAM may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service or energy in the same Operating Hour, provided that linked Energy and Off-Line Non-Spinning Reserve (Non-Spin) Resource-Specific Ancillary Service Offers are not awarded in the same Operating Hour.

(B) The sum of the awarded Resource-Specific Ancillary Service Offer capacities for each Resource must be within the Resource limits specified in the Current Operating Plan (COP) and Section 3.18, Resource Limits in Providing Ancillary Service, and the Resource Parameters as described in Section 3.7, Resource Parameters.

(C) Block Resource-Specific Ancillary Service Offers for a Load Resource – blocks will not be cleared unless the entire quantity block can be awarded. Because block Resource-Specific Ancillary Service Offers cannot set the Market Clearing Price for Capacity (MCPC), a block Ancillary Service Offer may clear below the Ancillary Service Offer price for that block.

(D) Block DAM Energy Bids, DAM Energy-Only Offers, and PTP Obligation bids – blocks will not be cleared unless the entire time and/or quantity block can be awarded. Because quantity block bids and offers cannot set the Settlement Point Price, a quantity block bid or offer may clear in a manner inconsistent with the bid or offer price for that block.

(E) Combined Cycle Generation Resources – The DAM may commit a Combined Cycle Generation Resource in a time period that includes the last hour of the Operating Day only if that Combined Cycle Generation Resource can transition to a shutdown condition in the DAM Operating Day.

(F) Energy Storage Resources (ESRs) – The energy cleared for an ESR may be negative, indicating purchase of energy, or positive, indicating sale of energy.

(d) Ancillary Service needs will be reflected in ASDCs for each Ancillary Service. Self-Arranged Ancillary Service Quantities will first be used to meet the ASDCs, and the remaining Ancillary Service needs are met from Ancillary Service Offers, as long as the costs do not exceed the ASDC value. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service.

(5) ERCOT shall determine the appropriate Load distribution factors to allocate offers, bids, and source and sink of CRRs at a Load Zone across the energized power flow buses that are modeled with Load in that Load Zone The non-Private Use Network Load distribution factors are based on historical State Estimator (SE) hourly distribution using a proxy day methodology representing anticipated weather conditions. The Private Use Network Load distribution factors are based on an estimated Load value considering historical net consumption at all Private Use Networks. If ERCOT decides, in its sole discretion, to change the Load distribution factors for reasons such as anticipated weather events or holidays, ERCOT shall select an SE hourly distribution from a proxy day reasonably reflecting the anticipated Load in the Operating Day. ERCOT may also modify the Load distribution factors to account for predicted differences in network topology between the proxy day and Operating Day. ERCOT shall develop a

methodology, subject to Technical Advisory Committee (TAC) approval, to describe the modification of the proxy day bus-load distribution for this purpose

[NPRR1004: Replace paragraph (5) above with the following upon system implementation:]

(5) ERCOT shall determine the appropriate Load distribution factors to allocate offers, bids, and source and sink of PTP Obligations at a Load Zone across the energized power flow buses that are modeled with Load in that Load Zone. ERCOT shall derive DAM Load distribution factors with the set of Load distribution factors constructed in accordance with the ERCOT Load distribution factor methodology specified in paragraph (c) of Section 3.12, Load Forecasting. In the event the Load distribution factors are not available, the Load distribution factors for the most recent preceding Operating Day will be used.

(6) ERCOT shall allocate offers, bids, and source and sink of CRRs at a Hub using the distribution factors specified in the definition of that Hub in Section 3.5.2, Hub Definitions.

(7) A Resource that has a Three-Part Supply Offer cleared in the DAM may be eligible for Make-Whole Payment of the Startup Offer and Minimum Energy Offer submitted by the Qualified Scheduling Entity (QSE) representing the Resource under Section 4.6, DAM Settlement.

(8) The DAM Settlement is based on hourly MW awards and on Day-Ahead hourly Settlement Point Prices. All PTP Options settled in the DAM are settled based on the Day-Ahead Settlement Point Prices (DASPPs). ERCOT shall assign a Locational Marginal Price (LMP) to de-energized Electrical Buses for use in the calculation of the DASPPs by using heuristic rules applied in the following order:

(a) Use an appropriate LMP predetermined by ERCOT as applicable to a specific Electrical Bus; or if not so specified

(b) Use the following rules in order:

(i) Use average LMP for Electrical Buses within the same station having the same voltage level as the de-energized Electrical Bus, if any exist.

(ii) Use average LMP for all Electrical Buses within the same station, if any exist.

(iii) Use System Lambda.

(9) The Day-Ahead MCPC for each hour for each Ancillary Service is the Shadow Price for that Ancillary Service for the hour as determined by the DAM algorithm.

(10) Day-Ahead MCPCs shall not exceed the SWCAP. Ancillary Service Offers higher than corresponding Ancillary Service penalty factors, as defined in Appendix 2 of the Other Binding Document titled "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints," will not be awarded.

[NPRR1080: Delete paragraph (10) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly.]

(11~~0~~) If the Day-Ahead MCPC cannot be calculated by ERCOT, the Day-Ahead MCPC for the particular Ancillary Service is equal to the Day-Ahead MCPC for that Ancillary Service in the same Settlement Interval of the preceding Operating Day.

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[NPRR1008 and NPR1014: Delete paragraph (11~~0~~) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly.]

(12~~1~~) If the DASPPs cannot be calculated by ERCOT, all CRRs shall be settled based on Real-Time prices. Settlements for all CRRs shall be reflected on the Real-Time Settlement Statement.

(13~~2~~) Constraints can exist between the generator's Resource Connectivity Node and the Resource Node, in which case the awarded quantity of energy may be inconsistent with the clearing price when the constraint between the Resource Connectivity Node and the Resource Node is binding.

[NPRR1014: Replace paragraph (13~~2~~) above with the following upon system implementation:]   (13~~2~~) Constraints can exist between a Resource's Resource Connectivity Node and its Resource Node, in which case the awarded quantity of energy may be inconsistent with the clearing price when the constraint between the Resource Connectivity Node and the Resource Node is binding.

(14~~3~~) PTP Obligation bids shall not be awarded where the DAM clearing price for the PTP Obligation is greater than the PTP Obligation bid price plus $0.01/MW per hour.

6.4.9.2.2 SASM Clearing Process

(1) SASM procurement requirements are:

(a) ERCOT shall procure the additional quantity required of each Ancillary Service, less the quantity self-arranged, if applicable. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service.

(b) ERCOT shall select Ancillary Service Offers submitted by QSEs, such that:

(i) For each Ancillary Service being procured, other than Reg-Down, ERCOT shall select offers that minimize the overall offer-based cost of these Ancillary Services. For each of these Ancillary Services, if selection of the Resource offer exceeds ERCOT's required Ancillary Service quantity, then ERCOT shall select a portion of the Resource offer to meet the Ancillary Service quantity required. For Load Resources offering a block of capacity, ERCOT shall ignore the offer unless the entire block can be accepted.

(ii) For Reg-Down, ERCOT shall procure required quantities by selecting capacity in ascending order starting from the lowest-priced offer. ERCOT shall continue this selection process until the required quantity of Reg-Down is obtained. If selection of the Resource offer exceeds ERCOT's required Ancillary Service quantity, then ERCOT shall select a portion of the Resource offer to meet the Ancillary Service quantity required. For Load Resources offering a block of capacity, ERCOT shall ignore the offer unless the entire block can be accepted.

(iii) For each Ancillary Service Offer from an Off-Line Resource considered in a SASM, the offer will be awarded only if it can meet the start-up time of the Resource based on the current and the historical operational state of the Resource. If the start-up time cannot be met for the first hour of a block offer, then the whole block offer shall not be considered.

(c) If a QSE has submitted offers of the same Resource capacity for more than one Ancillary Service (sometimes called linked offers), ERCOT may not select any one part of that Resource capacity to provide more than one Ancillary Service in the same Operating Hour. ERCOT may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service in the same Operating Hour.

(d) The SASM MCPC for each hour for each service is the Shadow Price for the corresponding Ancillary Service constraint for the hour as determined by the SASM algorithm.

(e) SASM MCPCs for any Ancillary Service shall not exceed the SWCAP. Ancillary Service Offers higher than corresponding Ancillary Service penalty factors, as defined in Appendix 2 of the Other Binding Document titled "Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints," will not be awarded.

[NPRR1010: Delete Section 6.4.9.2.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

ERCOT Impact Analysis Report

NPRR Number	1080	NPRR Title	Ancillary Service Price Cap
Impact Analysis Date	June 3, 2021		
Estimated Cost/Budgetary Impact	Less than $5k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department. See Comments		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon ERCOT Board approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
A manual process will be defined to support the requirements of NPRR1080.

NPRR Comments

NPRR Number	1080	NPRR Title	Limiting Ancillary Service Price to System-Wide Offer Cap

Date	June 22, 2021

Submitter's Information	
Name	Public Utility Commission of Texas (PUCT) Staff
E-mail Address	marketanalysis@puc.texas.gov
Company	PUCT
Phone Number	512-936-7371
Cell Number	
Market Segment	Not Applicable

Comments

Public Utility Commission of Texas (PUCT) Staff submits these comments to express support of Nodal Protocol Revision Request (NPRR) 1080 as filed by ERCOT and the Independent Market Monitor (IMM). NPRR1080 would limit the Ancillary Service Market Clearing Prices for Capacity (MCPCs) to the effective System-Wide Offer Cap (SWCAP) as recommended in the IMM's 2020 State of the Market Report for the ERCOT Electricity Markets.[1] Staff agrees that the changes proposed in this NPRR are consistent with economic market design principles and will help prevent Ancillary Services pricing above the Value of Lost Load (VOLL) until Real-Time Co-optimization (RTC) can be implemented.

NPRR1080 was submitted by ERCOT and the IMM after discussion with the Commission at the June 3, 2021 PUCT Open Meeting. While a comprehensive analysis of the February 2021 events related to Winter Storm Uri and its impacts on the ERCOT wholesale electric market is ongoing, the IMM's report highlighted a pair of pricing flaws revealed by the event that merit urgent attention. These pricing flaws are addressed in NPRR1080 and NPRR1081, Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed.

NPRR1080 will prevent future extreme Ancillary Service prices such as cleared in the Day-Ahead Market (DAM) during Uri. For certain hours during the event, MCPCs were as high as over $25,000 per MW while the SWCAP was set at $9000 per MW due to the DAM algorithm's consideration of Resource opportunity costs and the high Ancillary Service penalty factors (ASPFs). Staff agrees with the IMM's assessment that economic market design principles dictate that the value of reserves procured to reduce the

[1] PUC Project No. 34677, Reports of the Independent Market Monitor for the ERCOT, Item No. 18, 2020 State of the Market Report, (May 28, 2021).

probability of losing Load should not exceed VOLL, which is equal to the SWCAP. NPRR1080, along with OBDRR030, Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap, will ensure MCPCs do not exceed SWCAP and amend the ASPFs to a value at or immediately below the SWCAP.

PUCT Staff appreciates the work by ERCOT stakeholders in granting NPRR1080 Urgent status and requests TAC pass NPRR1080, along with the corresponding OBDRR030, through for consideration at the June 28, 2021 Board of Directors meeting in order to implement the changes as expeditiously as possible.

Revised Cover Page Language

None

Revised Proposed Protocol Language

None

Board Report

NPRR Number	1081	NPRR Title	Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed
Date of Decision	June 28, 2021		
Action	Approved		
Timeline	Urgent - Urgent status is necessary to align scarcity pricing with operational actions as quickly as possible.		
Effective Date	July 1, 2021		
Priority and Rank Assigned	Priority – 2021; Rank – 3340		
Nodal Protocol Sections Requiring Revision	6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) modifies the calculation of the Real-Time On-Line Reliability Deployment Price Adder so that the combination of System Lambda, the Real-Time On-Line Reserve Price Adder, and the Real-Time On-Line Reliability Deployment Price Adder will be equal to the Value of Lost Load (VOLL) when ERCOT is directing firm Load shed during Energy Emergency Alert (EEA) Level 3.		
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	During the February 2021 winter event, Real-Time Market (RTM) prices initially cleared well below the VOLL even while firm Load was being shed in EEA Level 3. Recognizing that this outcome was “inconsistent with the fundamental design of the ERCOT market,” the Public Utility Commission of Texas (PUCT) issued an order requiring ERCOT to “ensure that firm load that is being shed in EEA 3 is		

	accounted for in ERCOT's scarcity pricing signals." See *Second Order Directing ERCOT to Take Action and Granting Exception to Commission Rules*, Project 51617 (Feb. 16, 2021). In conformance with the PUCT's order, ERCOT temporarily adjusted the calculation of the Real-Time On-Line Reliability Deployment Price Adder to account for the MW value of the directed Load shed. Consistent with the action directed by the PUCT in February, ERCOT and the Independent Market Monitor (IMM) are now proposing a more permanent solution that will modify the calculation of the Real-Time On-Line Reliability Deployment Price Adder when firm Load is being shed in EEA Level 3, which is an out-of-market reliability action. The revised calculation will ensure that the combination of System Lambda, the Real-Time On-Line Reserve Price Adder, and the Real-Time On-Line Reliability Deployment Price Adder will be equal to the VOLL when ERCOT is directing firm Load shed during EEA Level 3. This will ensure that Real-Time energy prices reflect the VOLL when Load is being shed, which is fundamental to an energy-only market design in order to provide effective economic signals. This NPRR does not modify the language for the Real-Time On-Line Reliability Deployment Price Adder in the grey box for NPRR1010, RTC – NP 6: Adjustment Period and Real-Time Operations. Further discussions with stakeholders related to the Real-Time Reliability Deployment Price Adders for Ancillary Services are needed before these revisions can be proposed. ERCOT and the IMM plan to initiate these discussions prior to implementation of the Real-Time Co-Optimization (RTC) project. ERCOT and the IMM are requesting Urgent status to align pricing outcomes with stakeholders' expectations as quickly as possible. ERCOT and the IMM intend to bring a separate NPRR with additional changes including a recall period analogous to the recall period for Emergency Response Service (ERS) as well as reporting changes for the firm Load shed amount.
Credit Work Group Review	See 6/16/21 Credit WG comments
PRS Decision	On 6/10/21, PRS unanimously voted via roll call to grant NPRR1081 Urgent status. PRS then voted via roll call to recommend approval of NPRR1081 as submitted; and to forward to TAC NPRR1081 and the Impact Analysis with a recommended priority of 2021 and rank of 3340 and a recommended effective date of upon ERCOT Board approval. There were three abstentions from the Consumer (Occidental Chemical), Cooperative (LCRA), and Independent Generator (Luminant) Market Segments. All Market Segments participated in both votes.

Summary of PRS Discussion	On 6/10/21, the sponsors provided an overview of NPRR1081, the Impact Analysis, and the request for Urgent status. The sponsors clarified that the proposed changes in NPRR1081 would only apply during system-wide Load shed, not for localized events. Some participants voiced concerns over the exact end-point of a Load shed event and the procedures for exiting EEA Level 3, which the sponsors noted in the Business Case should be addressed in a future NPRR.
TAC Decision	On 6/23/21, TAC voted via roll call to recommend approval of NPRR1081 as recommended by PRS in the 6/10/21 PRS Report as amended by the 6/16/21 ERCOT comments with a recommended effective date of July 1, 2021. There were four abstentions from the Independent Generator (Luminant), Independent Retail Electric Provider (IREP) (2) (Just Energy and Chariot Energy), and Municipal (Garland) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/23/21, participants reviewed comments filed for NPRR1081. Participants debated the potential benefits and consequences of the concept proposed in the 6/17/21 LCRA comments; and generally supported the concept but desired additional to time for review and encouraged filing a separate NPRR for consideration.
ERCOT Opinion	ERCOT supports approval of NPRR1081.
Board Decision	On 6/28/21, the ERCOT Board approved NPRR1081 as recommended by TAC in the 6/23/21 TAC Report.

Sponsor	
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Market Segment	Not applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
Payless Power 060921	Opposed NPRR1081 as written and expressed concern that the sort of policy-making proposed within NPRR1081 should reside with the PUCT rather than within the Protocols
Credit WG 061621	Endorsed NPRR1081 noting positive credit impacts as it better aligns pricing outcomes with market expectations, and the current credit calculations take into account the changes of this NPRR
ERCOT 061621	Clarified that only the firm Load shed authorized by Section 6.5.9.4.2, EEA Levels, will be taken into consideration in determining the Real-Time On-Line Reliability Deployment Price Adder and that the adjustment to the Real-Time On-Line Reliability Deployment Price Adder based on firm Load shed ends once ERCOT is no longer directing firm Load shed
LCRA 061721	Proposed edits to Sections 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge, and 6.7.6, Real-Time Ancillary Service Imbalance Revenue Neutrality Allocation, to remove the Real-Time On-Line Reliability Deployment Price Adder from Ancillary Service imbalance Settlement
ERCOT 062221	Responded to the 6/17/21 LCRA comments, opined that the issues raised by LCRA require further discussion as a separate NPRR, and reiterated support for the 6/16/21 ERCOT comments
PUCT Staff 062221	Endorsed NPRR1081 as amended by the 6/16/21 ERCOT comments
RWE and Invenergy 062321	Opposed NPRR1081

Market Rules Notes

None

Proposed Protocol Language Revision

6.5.7.3.1 Determination of Real-Time On-Line Reliability Deployment Price Adder

(1) The following categories of reliability deployments are considered in the determination of the Real-Time On-Line Reliability Deployment Price Adder:

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (12) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than Controllable Load Resources;

(d) Deployed Emergency Response Service (ERS);

(e) Real-Time DC Tie imports during an EEA where the total adjustment shall not exceed 1,250 MW in a single interval;

(f) Real-Time DC Tie exports to address emergency conditions in the receiving electric grid;

(g) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;~~ and~~

(h) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid; and~~.~~

(i) ERCOT-directed firm Load shed during EEA Level 3, as described in paragraph (3) of Section 6.5.9.4.2, EEA Levels.

(2) The Real-Time On-Line Reliability Deployment Price Adder is an estimation of the impact to energy prices due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, after the two-step SCED process and also after the Real-Time On-Line Reserve Price Adder and Real-Time Off-Line Reserve Price Adder have been determined, the Real-Time On-Line Reliability Deployment Price Adder is determined as follows:

(a) For RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line, set the LSL, LASL, and LDL to zero.

(b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity, set the LSL, LASL, and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction.

(c) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes * SCED Down Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes*SCED Up Ramp Rate), or HASL.

(d) For all Controllable Load Resources excluding ones with a telemetered status of OUTL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes * SCED Up Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes*SCED Down Ramp Rate), or HASL.

(e) Add the deployed MW from Load Resources other than Controllable Load Resources to GTBD linearly ramped over the 10-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the amount of MW added to GTBD during the restoration period will be determined by validated telemetry. The TAC shall review the validity of the prices for the bid curve at least annually.

(f) Add the deployed MW from ERS to GTBD. The amount of deployed MW is determined from the XML messages and ERS contracted capacities for the ERS Time Periods when ERS is deployed. After recall, an approximation of the amount of un-restored ERS shall be used. After ERCOT recalls each group, GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours").

The above parameter is defined as follows:

Parameter	**Unit**	**Current Value***
RHours	Hours	4.5
* Changes to the current value of the parameter(s) referenced in this table above may be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(g) Add the MW from Real-Time DC Tie imports during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(h) Subtract the MW from Real-Time DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(i) Add the MW from energy delivered to ERCOT through registered BLTs during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(j) Subtract the MW from energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(k) Perform a SCED with changes to the inputs in items (a) through (j) above, considering only Competitive Constraints and the non-mitigated Energy Offer Curves.

(l) Perform mitigation on the submitted Energy Offer Curves using the LMPs from the previous step as the reference LMP.

(m) Perform a SCED with the changes to the inputs in items (a) through (j) above, considering both Competitive and Non-Competitive Constraints and the mitigated Energy offer Curves.

(n) Determine the positive difference between the System Lambda from item (m) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(o) Determine the amount given by the Value of Lost Load (VOLL) minus the sum of the System Lambda of the second step in the two step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder.

(p) The Real-Time On-Line Reliability Deployment Price Adder is the minimum of items (n) and (o) above except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time On-Line Reliability Deployment Price Adder is the VOLL minus the sum of the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder. Once ERCOT is no longer directing firm Load shed, as described above, the Real-Time On-Line Reliability Deployment Price Adder will again be set as the minimum of items (n) and (o) above.

[NPRR904, NPRR1006, NPRR1010, and NPRR1014: Replace applicable portions of Section 6.5.7.3.1 above with the following upon system implementation for NPRR904, NPRR1006, or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.3.1 Determination of Real-Time Reliability Deployment Price Adder

(1) The following categories of reliability deployments are considered in the determination of the Real-Time Reliability Deployment Price Adder for Energy, and the Real-Time Reliability Deployment Price Adders for Ancillary Services:

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (12) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than Controllable Load Resources;

(d) Deployed Emergency Response Service (ERS);

(e) ERCOT-directed DC Tie imports during an EEA or transmission emergency where the total adjustment shall not exceed 1,250 MW in a single interval;

(f) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;

(g) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT where the total adjustment shall not exceed 1,250 MW in a single interval;

(h) ERCOT-directed DC Tie exports to address emergency conditions in the receiving electric grid where the total adjustment shall not exceed 1,250 MW in a single interval;

(i) ERCOT-directed curtailment of DC Tie exports below the DC Tie advisory export limit as of 0600 in the Day-Ahead or subsequent advisory export limit during EEA, a transmission emergency, or to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;

(j) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;

(k) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid; and

(l) ERCOT-directed deployment of Transmission and/or Distribution Service Provider (TDSP) standard offer Load management programs.(2) The Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Services are estimations of the impact to energy prices and Real-Time MCPCs due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, the Real-Time Reliability Deployment Price Adder for Energy and Real-Time Reliability Deployment Price Adders for Ancillary Services are determined as follows:

(a) For RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line:

(i) Set the LSL and LDL to zero;

(ii) Remove all Ancillary Service Offers; and

(iii) For the first step of SCED, administratively set the Energy Offer Curve for the Resource at a value equal to the Power Balance Penalty Price (PBPP) for all capacity between 0 MW and the HSL of the Resource.

(b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity:

(i) Set the LSL and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction;

(ii) Set the maximum Ancillary Service capabilities of the Resource equal to the minimum of their current value and COP Ancillary Service capabilities of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction; and

(iii) For the first step of SCED, administratively set the Energy Offer Curve for the Resource at a value equal to the Power Balance Penalty Price (PBPP) for the additional capacity of the Resource, defined as the positive difference between the Resource's current telemetered HSL and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction.

(c) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:

(i) If the Generation Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the Generation Resource SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(d) For all On-Line ESRs:

(i) If the ESR SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the ESR SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(e) For all Controllable Load Resources excluding ones with a telemetered status of OUTL:

(i) If the Controllable Load Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the Controllable Load Resource SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(f) Add the deployed MW from Load Resources other than Controllable Load Resources to GTBD linearly ramped over the 10-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the amount of MW added to GTBD during the restoration period will be determined by validated telemetry. The TAC shall review the validity of the prices for the bid curve at least annually.

(g) Add the deployed MW from ERS to GTBD. The amount of deployed MW is determined from the XML messages and ERS contracted capacities for the ERS Time Periods when ERS is deployed. After recall, an approximation of the amount of un-restored ERS shall be used. After ERCOT recalls each group, GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours").

The above parameter is defined as follows:

Parameter	**Unit**	**Current Value***
RHours	Hours	4.5
* Changes to the current value of the parameter(s) referenced in this table above may be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(h) Add the MW from DC Tie imports during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(i) Add the MW from DC Tie export curtailments during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator. The MW added to GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for exports on that tie as of 0600 in the Day-Ahead or subsequent advisory export limit minus the aggregate export on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.

(j) Subtract the MW from DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(k) Subtract the MW from DC Tie import curtailments to address local transmission system limitations or emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator. The MW subtracted from GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for imports on that tie as of 0600 in the Day-Ahead or subsequent advisory import limit minus the aggregate import on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.

(l) Add the MW from energy delivered to ERCOT through registered BLTs during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(m) Subtract the MW from energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(n) Add the deployed MWs from TDSP standard offer Load management programs to GTBD, if ERCOT instructs TDSPs to deploy their standard offer Load management programs. The amount of deployed MW is the value ERCOT provided for all TDSP standard offer Load management programs in the most current May Report on Capacity, Demand and Reserves in the ERCOT Region, unless modified as specified in this paragraph. If ERCOT is informed that all or a portion of a TDSP's standard offer Load management program has been fully exhausted, or has been expanded as the result of a Public Utility Commission of Texas (PUCT) proceeding, ERCOT will remove the associated MW value of any exhausted capacity from the amount of deployed MW or, in the case of an expansion, ERCOT will request an updated MW value from the relevant TDSPs to use in place of the May Report on Capacity, Demand and Reserves in the ERCOT Region value for that year. The initial value ERCOT will use for deployed MW under this paragraph for each calendar year, as well as any subsequent changes to this value, will be communicated to Market Participants in a Market Notice. After recall, an approximation of the amount of un-restored TDSP standard offer Load management programs shall be used. GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours") defined by item (g) above.

(o) Perform a SCED with changes to the inputs in items (a) through (m) above, considering only Competitive Constraints and the non-mitigated Energy Offer Curves.

(p) Perform mitigation on the submitted Energy Offer Curves using the LMPs from the previous step as the reference LMP.

(q) Perform a SCED with the changes to the inputs in items (a) through (m) above, considering both Competitive and Non-Competitive Constraints and the mitigated Energy offer Curves.

(r) The Real-Time Reliability Deployment Price Adder for Energy is equal to the positive difference between the System Lambda from item (q) above and the

System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(s) For each individual Ancillary Service, the Real-Time Reliability Deployment Price Adder for Ancillary Service is equal to the positive difference between the MCPC for that Ancillary Service from item (q) above and the MCPC for that Ancillary Service.

ERCOT Impact Analysis Report

NPRR Number	1081	NPRR Title	Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed
Impact Analysis Date	June 3, 2021		
Estimated Cost/Budgetary Impact	Between $25k and $45k Additional Cost to Implement in Passport: N/A		
Estimated Time Requirements	The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon ERCOT Board prioritization and approval. Please see the Project Priority List (PPL) for additional information. Estimated project duration: 2 to 3 months in current systems Passport Schedule Risk Assessment: No Risk to Schedule		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Market Operation Systems 45% • Data Management & Analytic Systems 28% • Energy Management Systems (EMS) 27%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	ERCOT will update grid operations and practices to implement this NPRR.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
In the interim, ERCOT would utilize existing system work-arounds in order to effectuate the pricing outcomes proposed by this NPRR.

Comments
See interim solution proposed above.

NPRR Comments

NPRR Number	1081	NPRR Title	Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed

Date	June 22, 2021

Submitter's Information	
Name	Public Utility Commission of Texas (PUCT) Staff
E-mail Address	marketanalysis@puc.texas.gov
Company	PUCT
Phone Number	512-936-7371
Cell Number	
Market Segment	Not Applicable

Comments

Public Utility Commission of Texas (PUCT) Staff submits these comments to express support of Nodal Protocol Revision Request (NPRR) 1081 as amended by the 6/16/21 ERCOT comments. NPRR1081 would modify the calculation of the Real-Time On-Line Reliability Deployment Price Adder to consider ERCOT-directed firm Load shed during an Energy Emergency Alert (EEA) Level 3 event as recommended in the Independent Market Monitor's (IMM's) 2020 State of the Market Report for the ERCOT Electricity Markets.[1] Staff agrees that ensuring Real-Time energy prices reflect the Value of Lost Load (VOLL) when Load is being shed is a necessary and fundamental economic signal in an energy-only market design.

NPRR1081 was submitted by ERCOT and the IMM after discussion with the Commission at the June 3, 2021 PUCT Open Meeting. While a comprehensive analysis of the February 2021 events related to Winter Storm Uri and its impacts on the ERCOT wholesale electric market is ongoing, the IMM's report highlighted a pair of pricing flaws revealed by the event that merit urgent attention. These pricing flaws are addressed in NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap, and NPRR1081.

Consistent with the direction provided during Uri, NPRR1081 will provide a permanent pricing solution for when out-of-market reliability actions are taken by ERCOT to ensure grid stability. Firm Load shed during an EEA 3 event to maintain sufficient Physical Responsive Capability (PRC) or stabilize grid frequency is an out-of-market reliability action and therefore should be reflected in Real-Time energy prices. In such an event, Real-Time energy prices should reflect cost equal to VOLL which is equal to the System-Wide Offer Cap (SWCAP). Staff agrees with the IMM's assessment that efficient pricing is needed during extreme shortages to provide the economic signals necessary to

[1] PUC Project No. 34677, Reports of the Independent Market Monitor for the ERCOT, Item No. 18, 2020 State of the Market Report, (May 28, 2021)

increase the generation needed to restore Load in the short-term and service it reliably over the long-term.

PUCT Staff appreciates the work by ERCOT stakeholders in granting NPRR1081 Urgent status and requests TAC pass NPRR1081 through for consideration at the June 28, 2021 Board of Directors meeting in order to implement the changes as expeditiously as possible.

Revised Cover Page Language

None

Revised Proposed Protocol Language

None

Board Report

OBDRR Number	<u>030</u>	**OBDRR Title**	**Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap**
Date of Decision	June 28, 2021		
Action	Approved		
Effective Date	Upon system implementation of Nodal Protocol Revision Request (NPRR) 1080, Limiting Ancillary Service Price to System-Wide Offer Cap		
Priority and Rank Assigned	Not applicable		
Other Binding Document Requiring Revision	Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints		
Supporting Protocol or Guide Section(s) / Related Documents	NPRR1080		
Revision Description	This Other Binding Document Revision Request (OBDRR) changes the Ancillary Service penalty factors to the effective System-Wide Offer Cap (SWCAP).		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the <u>ERCOT Strategic Plan</u> or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*		
Business Case	This is the companion OBDRR to NPRR1080. This OBDRR sets the Ancillary Service penalty factors equal to or immediately below the SWCAP in the Day-Ahead Market (DAM) and Supplemental Ancillary Services Market (SASM) engines. Setting the Ancillary Service penalty factors at or near the SWCAP will prevent Ancillary Service Shadow Prices from exceeding the SWCAP, thereby limiting the Market Clearing Prices for Capacity (MCPCs), as set forth in NPRR1080. The Ancillary Service penalty factors for Responsive Reserve (RRS) and Non-Spinning Reserve (Non-Spin) are \$0.01/MWh and \$0.03/MWh below the SWCAP, respectively, in order		

	to allow the DAM and SASM clearing engines to prioritize the different Ancillary Service products.
TAC Decision	On 6/23/21, TAC voted via roll call to recommend approval of OBDRR030 as submitted and the Impact Analysis for OBDRR030. There were three abstentions from the Cooperative (STEC) and Independent Generator (2) (Luminant and Calpine) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/23/21, there was no discussion.
ERCOT Opinion	ERCOT supports approval of OBDRR030.
Board Decision	On 6/28/21, the ERCOT Board approved OBDRR030 as recommended by TAC in the 6/23/21 TAC Report.

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Market Rules Notes

Please note that the following OBDRR(s) also propose revisions to this Other Binding Document:

- OBDRR026, Change Shadow Price Caps to Curves and Remove Shift Factor Threshold

Proposed Other Binding Document Language Revision

1. PURPOSE

Protocol Section 6.5.7.1.11, Transmission Network and Power Balance Constraint Management, requires the ERCOT Board to approve ERCOT's methodology for establishing caps on the Shadow Prices for transmission constraints and the Power Balance constraint. Additionally, the ERCOT Board must also approve the values (in $/MWh) for each of the Shadow Price caps.

The effect of the Shadow Price cap for transmission network constraints is to limit the cost calculated by the Security-Constrained Economic Dispatch (SCED) optimization to resolve an additional MW of congestion on a transmission network constraint to the designated maximum Shadow Price for that transmission network constraint. The effect of the Shadow Price cap for the Power Balance Constraint is to limit the cost calculated by the SCED optimization when the instantaneous amount of generation to be dispatched does not equal the instantaneous demand of the ERCOT system. In this case, the cost calculated by SCED to resolve either the addition or reduction of one MW of dispatched generation on the power balance constraint is limited to the maximum Shadow Price for the power balance constraint, which is also referred to as the Power Balance Penalty.

The maximum Shadow Prices for the transmission network constraints and the power balance constraint directly determine the Locational Marginal Prices (LMPs) for the ERCOT Real Time Market in the cases of constraint violations.

This Business Practice describes:

- the ERCOT Board approved methodology that the ERCOT staff will use for determining the maximum system-wide Shadow Prices for transmission network constraints and for the power balance constraint, and
- the ERCOT Board approved Shadow Price caps and their effective date.

2. BACKGROUND DISCUSSION

The term Shadow Price as used in a constrained optimization problem in economics, is usually defined as the change in the objective value of the optimal solution of the optimization problem obtained by changing each constraint, one-at-a-time, by one unit. In the SCED process the objective function to be minimized by the SCED optimization engine is the total system dispatch cost required to maintain the system power balance and to resolve congestion of the transmission network as specified in the transmission constraint input set. The term Shadow Price is used in the context of individual constraints, whether a transmission network constraints or power balance constraint. Consistent with the definition of the Shadow Price, in a minimization problem, such as the SCED, the Shadow Prices for the transmission constraints are different for each transmission constraint and they are positive $/MW amounts defined as increase of the system dispatch costs if a transmission line limit is decreased by one MW. The Shadow Price for the Power Balance constraint represents system costs for serving the last MW of load. The Power Balance Penalty can be either positive (if the system requires additional generation) or negative (if the system requires a reduction in generation). If a constraint is not binding, meaning the constraint has excess capability under the given system conditions, the Shadow Price of the constraint is \$0.00/MWh. On the other hand, if the constraint is binding, meaning it is limiting because the system conditions are such that the constraint limit is exactly met by the SCED selected dispatch pattern, the constraint Shadow Price is a non-zero \$/MW value and when the maximal Shadow Price (i.e. the Shadow Price cap) is reached the constraint will be violated without further increases in the constraint Shadow Price.

In the context of the SCED optimization, the Shadow Prices give rise to the application of a transmission penalty cost and a power balance penalty cost in the SCED objective function that results in an increase in the total system dispatch cost. On the other hand, the transmission network constraint Shadow Prices and the Power Balance Shadow Price directly determine the LMPs (in \$/MWh) calculated in the SCED. The LMPs will be limited because of the Shadow Price cap amounts, expressed in \$/MWh.

For the network transmission constraints, the Shadow Price Cap may vary for each constraint, may be a unique value applicable to all constraints, or may be values unique to subsets of the full constraint set. For the Power Balance constraint, the Shadow Price Cap may be a single value or a value given as a function of the amount of the power balance mismatch (instantaneous generation to be dispatch minus instantaneous demand) in MW.

[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

For the network transmission constraints, the Shadow Price Cap may vary for each constraint, may be a unique value applicable to all constraints, or may be values unique to subsets of the full constraint set. For the Power Balance constraint, the Shadow Price Cap is a single value.

3. ELEMENTS FOR METHODOLOGY FOR SETTING THE NETWORK TRANSMISSION SYSTEM-WIDE SHADOW PRICE CAPS

3.1 Congestion LMP Component

The LMPs at Electrical Buses are calculated as follows:

$$LMP_{EB} = \lambda - \sum_{line} SF_{EB}^{line} \cdot SP^{line}$$

Where:

LMP_{EB}	is LMP at Electrical Bus *EB*
λ	is system lambda (Shadow Price of power balance)
SF_{EB}^{line}	is Shift Factor for Electrical Bus *EB* for transmission *line*
SP^{line}	is Shadow Price for transmission *line*.

Note that the Shadow Prices for congested transmission lines are positive, otherwise they are equal zero. The Shift Factors for Electrical Buses on one side of transmission line are negative and for Electrical Buses on the other side of transmission line are positive.

The congestion component of Electrical Bus LMP is:

$$\Delta LMP_{EB}^{cong} = -\sum_{line} SF_{EB}^{line} \cdot SP^{line}$$

and it can be positive or negative depending on sign of Shift Factors. The congestion component of LMP represents a price incentive to generation units connected at that Electrical Bus to increase or decrease power output to manage network congestion. Note that only marginal units (i.e. units that are able to move, not those dispatched at min/max dispatch limits to resolve other constraints or to provide energy to the system) can participate in resolving network congestion and determining the system lambda for a particular iteration of SCED.

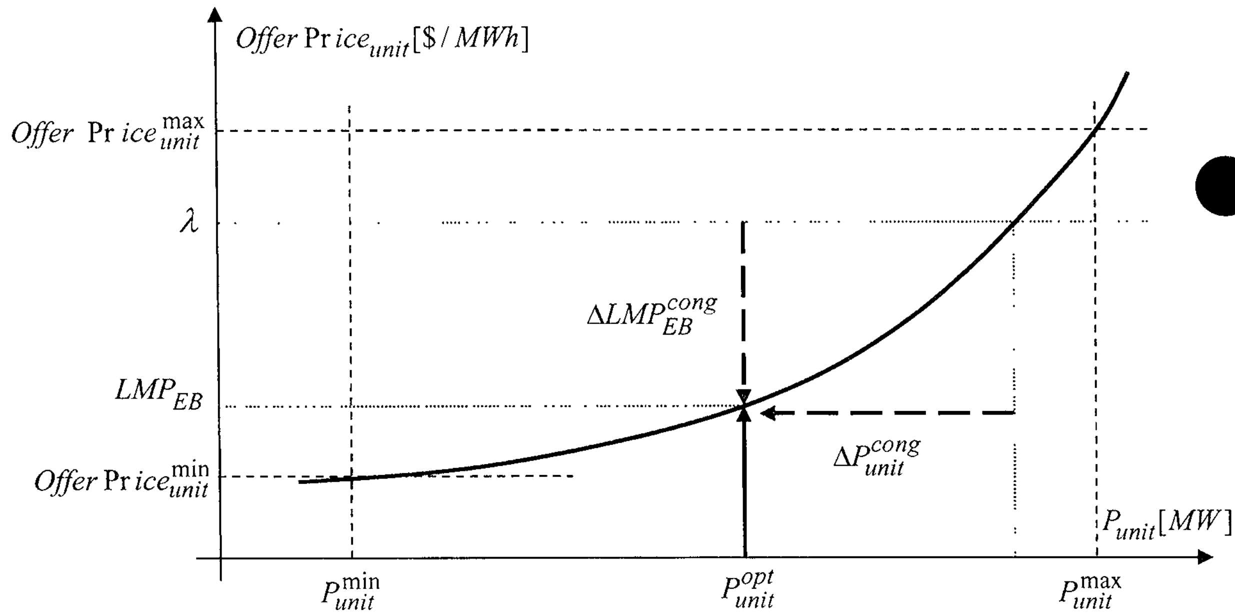
The optimal dispatch from both system (minimal congestion costs) and unit (maximal unit profit) prospective is determined by condition:

$$\mathit{Offer}\ \mathrm{Pr}\,ice_{unit}(P_{unit}^{opt}) = LMP_{EB}\,.$$

The generation unit response to pricing signal will result in line power flow reduction in amount:

$$\Delta P^{line} = SF_{EB}^{line} \cdot \Delta P_{unit}^{cong}$$

These relationships are illustrated at the following figure:



3.2 Network Congestion Efficiency

The following three elements of network congestion management determine the efficiency of generating unit participation (as defined above):

- Line power flow contribution ΔP^{line}
- LMP congestion component ΔLMP_{EB}^{cong}
- Unit power output adjustment ΔP_{unit}^{cong}.

The line power contribution is determined by its Shift Factor directly. It may be established that generating units with Shift Factors below specified threshold (10%) are not efficient in network congestion.

The LMP congestion component is main incentive controlling generating unit dispatch. It is determined by Shift Factors and Shadow Prices for transmission constraints:

$$\Delta LMP_{EB}^{cong} = \sum_{line} SF_{EB}^{line} \cdot SP^{line}.$$

Generating units with small Shift Factors (i.e. below Shift Factor threshold) will not be as effective in resolving constraints as will generators with higher shift factors on the constraint. If there is no efficient generating units then Shadow Price must be increased to get enough contribution from inefficient units. Therefore, high Shadow Prices indicate inefficient congestion management.

The maximal value of LMP congestion component $\Delta LMP_{\max}^{cong}$ directly limits the transmission congestion costs:

$$C_{\cos t}^{cong} = \sum_{unit} \Delta LMP_{\max}^{cong} \cdot P_{unit}^{opt}.$$

The efficiency of generating unit contribution can be determined by maximal value of LMP congestion component $\Delta LMP_{\max}^{cong}$ (say \$500/MWh). The maximal Shadow Price for transmission constraint can be established by Shift Factor efficiency threshold and maximal LMP congestion component as follows:

$$SP_{\max} = \Delta LMP_{\max}^{cong} / SF_{threshold}^{efficiency}.$$

The maximal unit power output adjustment $\Delta P_{\max}^{cong}$ will be determined by condition:

$$Offer\ \Pr ice_{unit}(P_{unit} - \Delta P_{\max}^{cong}) = LMP_{EB} = \lambda - SF_{threshold}^{efficency} \cdot SP_{\max}$$

3.3 Shift Factor Cutoff

Note: This Shift Factor cutoff is not related to above Shift Factor efficiency threshold used for determination of maximal Shadow Price.

Some generating units can be excluded from network congestion management by ignoring their contribution in line power flows. Note that this exclusion cannot be performed physically, i.e. all units will always contribute to line power flows according to their Shift Factors. Therefore, the Shift Factor cutoff introduces an additional approximation into line power flow modeling.

Since the effect of the Shift Factors below the cut off on the overload are ignored in the optimization, any Shift Factor cutoff will cause additional re-dispatch of the remaining generating units participating in the management of congestion on the constraint. I.e. Generation Resources with Shift Factor above cut off will have to be moved more to account for the increase in overload caused by increasing generation of an inexpensive Resource with positive Shift Factor below cut off and decreasing generation of an expensive Resource with negative Shift Factor below cut off.

The Shift Factor cutoff will cause mismatch between optimized line power flow and actual line power flow that will happen when dispatch Base Points are deployed. This mismatch can degrade the efficiency of congestion management.

The Shift Factor cutoff can reduce volume of Shift Factor data and filter out numerical errors in calculating Shift Factors. Currently the default value of Shift Factor cut off is 0.0001) and is implemented at the EMS to reduce the amount of data transferred to MMS. Any threshold above that level will cause a distortion of congestion management process.

3.4 Methodology Outline

The methodology for determination of maximal Shadow Prices for transmission constraints could be based on the following setting:

(a) Determine Shift Factor efficiency threshold $SF_{threshold}^{efficiency}$ (default x%)

(b) Determine maximal LMP congestion component $\Delta LMP_{\max}^{cong}$ (default $y/MWh)

(c) Calculate maximal Shadow Price for transmission constraints:

$$SP_{\max} = \Delta LMP_{\max}^{cong} / SF_{threshold}^{efficiency}$$

(d) Determine Shift Factor cutoff threshold $SF_{threshold}^{cutoff}$ (default z%)

(e) Evaluate settings on variety of SCED save cases.

3.5 Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED

The Generic Transmission Shadow Price Caps noted below will be used in SCED unless ERCOT determines that a constraint is irresolvable by SCED. The methodology for determining and resolving an insecure state within SCED (i.e. SCED Irresolvable) is defined in Protocol Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm, whereas the subsequent trigger condition for the determination of that constraint's Shadow Price Cap is described in Section 3.6, Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED.

<u>Generic Transmission Constraint Shadow Price Caps in SCED</u>

- Base Case/Voltage Violation: $9,251/MW
- N-1 Constraint Violation

- Greater than 200 kV: $4,500/MW
- 100 kV to 200 kV: $3,500/MW
- Less than 100 kV: $2,800/MW

3.5.1 Generic Transmission Constraint Shadow Price Cap in SCED Supporting Analysis

Figure 1 is a contour map that shows the relationship between the level of the constraint shadow price cap, the offer price difference of the marginal units deployed to resolve a constraint, and the shift factor difference of the marginal units deployed to resolve a constraint.[1]

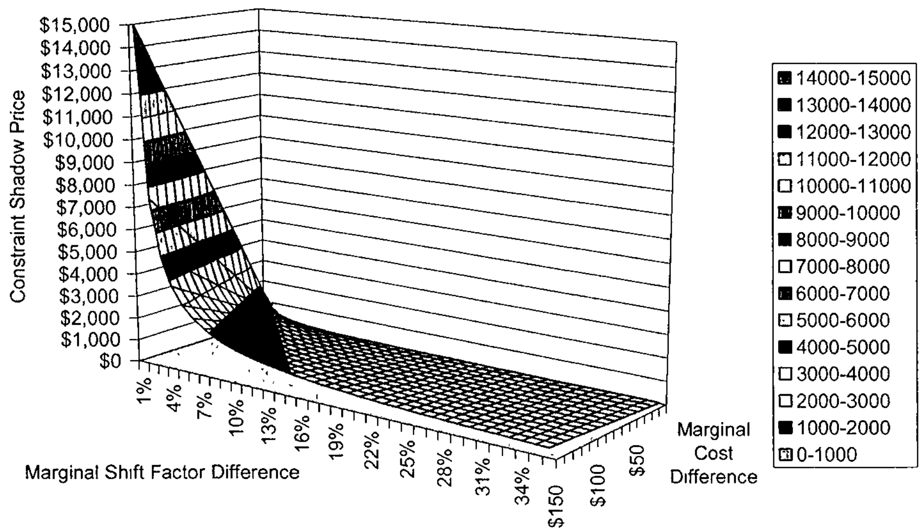


Figure 1

Figure 2 is a projection of Figure 1 onto the x-axis (*i.e.*, looking at it from the top). These two figures focus on constraint shadow price cap levels, and do not consider the interaction with the power balance constraint penalty factor, which is further discussed in association with Figure 4.

[1] A distributed load reference bus is assumed in this document, and all shift factor values refer to the flow on a constraint (either pre- or post-contingency) assuming an injection at the location in question and a withdrawal at the reference bus.

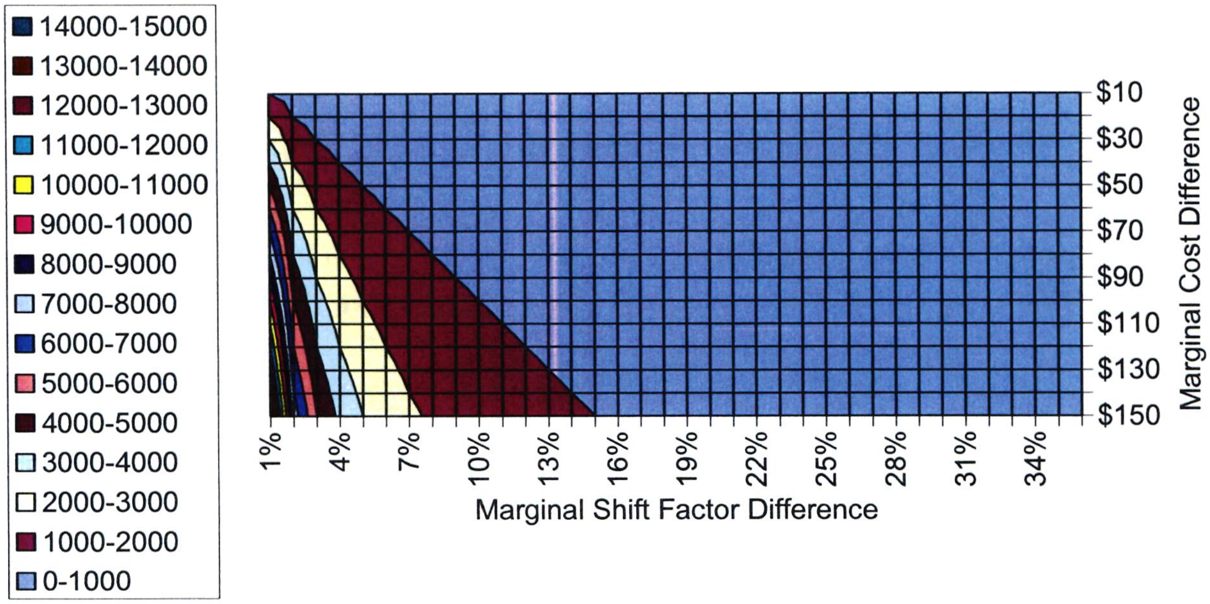


Figure 2

Figures 1 and 2 show that:

- For a constraint shadow price cap of $9,251/MW
  - Marginal units with an *offer price difference* of $92.51/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  - Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1.6%.
- For a constraint shadow price cap of $4,500/MW
  - Marginal units with an *offer price difference* of $45/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  - Marginal units with an *offer price difference* of $150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 3.4%.
- For a constraint shadow price cap of $3,500/MW
  - Marginal units with an *offer price difference* of $35/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.

  - Marginal units with an *offer price difference* of \$150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 4.3%.
- For a constraint shadow price cap of \$2,800/MW
  - Marginal units with an *offer price difference* of \$28/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 1%.
  - Marginal units with an *offer price difference* of \$150/MWh will be deployed to resolve a constraint when the *shift factor difference* of the marginal units is as low as 5.35%.

Figure 3 shows the maximum offer price difference of the marginal units that will be deployed to resolve congestion with each of the proposed shadow price cap values as a function of the shift factor difference of the marginal units.

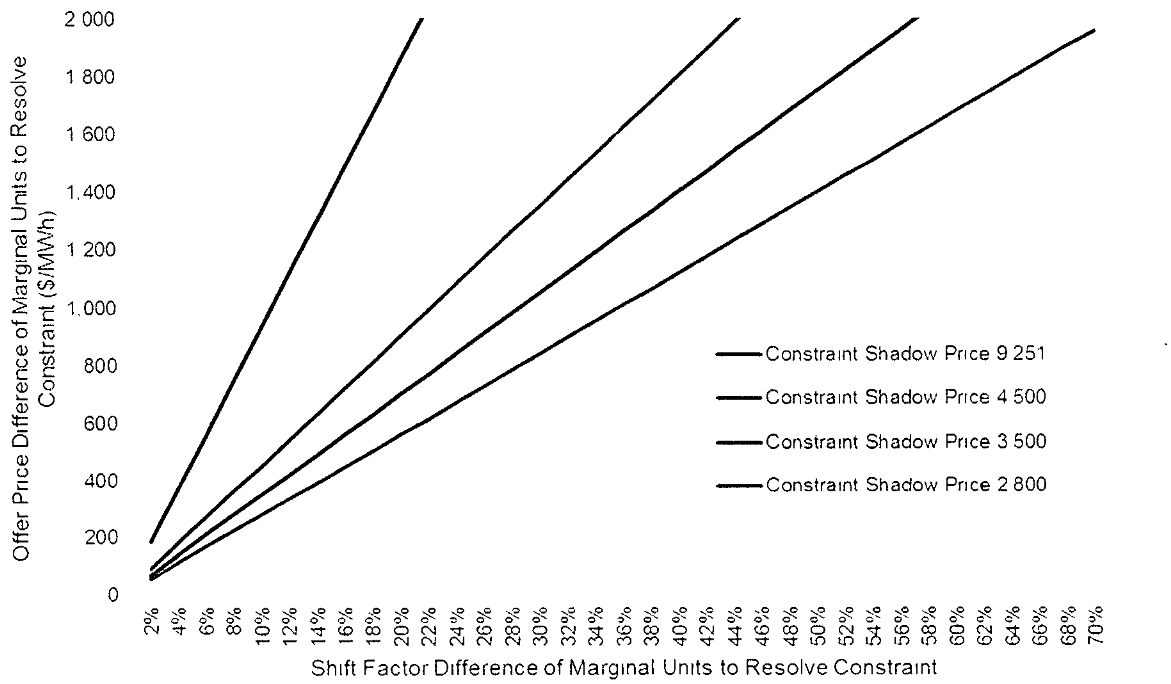


Figure 3

For example, with a shift factor difference of the marginal units of just 2%, the maximum offer price difference of the marginal units that will be deployed to resolve the constraint is \$56, \$70, \$90 and \$185.02/MWh for constraint shadow price cap values of \$2,800, \$3,500, \$4,500 and \$9,251/MW, respectively. Similarly, for with a shift factor difference of the marginal units of 60%, the maximum offer price difference of the marginal units that will be deployed to resolve the constraint is \$1,680, \$2,100, \$2,700 and \$5,550.60/MWh for constraint shadow price cap values of \$2,800, \$3,500, \$4,500 and \$9,251/MW, respectively.

In some circumstances these constraint shadow price cap values may preclude the deployment of a $9,000/MWh offer. However, it is not possible in the nodal design to establish constraint shadow price caps at a level that will always accept a $9,000/MWh offer and still produce pricing outcomes that remain within reasonable bounds of the subsection (g)(6) of P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, $9,000 offer cap. For example, taking the case above where the shift factor difference of the marginal units is just 2%, a constraint shadow price cap of $450,000/MW would be required to deploy $9,000/MWh offers to resolve the congestion (assuming an offer price of zero for the marginal constrained-down unit). In this case, for nodes with a higher shift factor relative to the constraint (regardless of whether the nodes are generation or load nodes), the resulting LMP would be significantly higher than the $9,000/MWh system-wide offer cap if the constraint was irresolvable. For example, a node with a shift factor of -50% would have an LMP with a congestion component of $225,000/MWh from just this one constraint, and even higher if multiple constraints are binding. In contrast, with a $9,251/MW shadow price cap, the congestion component of the LMP of the node with a shift factor of -50% would be $4,625.50/MW for just this one constraint.

The LMP at an individual node, hub or load zone can exceed the system-wide offer cap in some circumstances. This is most likely to occur when there are one or more irresolvable constraints on the system *and* when overall dispatchable supply on the system is tight. Relatively speaking, it is more likely that individual node prices will exceed the system-wide offer cap than hubs or load zones, but it is possible that hub or load zone prices could exceed the system-wide offer cap. It is not possible in the nodal system to assign constraint shadow price caps and power balance penalty factor values that achieve the desired reliability and efficiency objectives and ensure that all LMPs remain within the bounds of the system-wide offer caps under all circumstances.

Operationally once ERCOT reaches the shadow price cap, ERCOT may use the following method to manage congestion. Steps that may be taken by ERCOT operations to resolve congestion when the transmission constraint is violated in SCED after the Shadow Price reaches the shadow price cap include:

- Formulating a mitigation plan which may include
  - Transmission reconfiguration (switching)
  - Load rollover to adjacent feeders
  - Load shed plans
- Redistribution of ancillary services to increase the capacity available within a particular area.
- Commitment of additional units.

- Re-dispatching generation through over-riding High Dispatch Limit (HDL) and Low Dispatch Limit (LDL) in accordance with paragraph (3)(g) of Protocol Section 6.5.7.1.10.

3.6 Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED

ERCOT Operations is required to resolve security violations on the ERCOT Grid as described in Protocol Section 6, Adjustment Period and Real-Time Operations, and the associated Nodal Operating Guides and ERCOT will utilize the SCED application or direct actions on the transmission network and among Generation Resources, as needed, to resolve security violations. With regard to SCED operations, if a security violation on a constraint occurs, ERCOT will determine whether or not this constraint violation should be deemed to be irresolvable by online Generation Resource Dispatch by the SCED application. ERCOT will use the methodology described in this section to determine the Shadow Price Cap for a constraint that is deemed irresolvable pursuant to Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, below. For each of these constraints this Shadow Price Cap will be used by the SCED application in place of the generic cap specified by Section 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, until ERCOT deems the constraint resolvable by SCED. ERCOT shall provide the market 30 days notice before deeming the constraint resolvable by SCED. Upon deeming the constraint resolvable by SCED, the Shadow Price Cap for the constraint shall be determined pursuant to Section 3.5.

3.6.1 Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED

The methodology for determining and resolving an insecure state within SCED is defined in Protocol Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm. ERCOT shall modify the Shadow Price Cap for a transmission network constraint that is consistently irresolvable by SCED if either of the following two conditions are true. Intervals with manual overrides performed as a result of SCED not resolving the congestion, shall be included:

A. A constraint violation is not resolved by the SCED dispatch or overridden for more than two consecutive hours on more than 4 consecutive Operating Days; or
B. A constraint violation is not resolved by the SCED dispatch for more than a total of 20 hours in a rolling thirty day period.

On the Operating Day during which ERCOT deems a network transmission constraint to have met the trigger conditions, ERCOT shall identify the following Generation Resources:

C. The Generation Resource with the lowest absolute value of the negative shift factor impact on the violated constraint (this resource is referred as Generation Resource C in the Shadow Price Cap calculation below); and,

D. The Generation Resource with the highest absolute value of the negative shift factor on the violated constraint (this resource is referred to as Generation Resource D in the designation of the net margin Settlement Point Price (SPP) described below).

When determining Generation Resources C and D above, ERCOT shall ignore all Generation Resources that have a shift factor with an absolute value of less than 0.02 impact on the irresolvable constraint.

3.6.2 Methodology for Setting the Constraint Shadow Price Cap for a Constraint that is Irresolvable in SCED

The Shadow Price Cap for a constraint that has met the trigger conditions described in Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, and the Shadow Price Cap for any constraint that has the same overloaded transmission element and direction as a constraint that has met the trigger conditions, will be determined as follows.
The Shadow Price Cap on the constraint that has met the trigger conditions described in Section 3.6.1, will be set to the minimum of E or F as follows:

E. The value of the Generic Shadow Price Cap as determined in Section 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, and
F. The Maximum of the either the largest value of the Mitigated Offer Cap for Generation Resource C, as determined above, divided by the absolute value of its shift factor impact on the constraint or $2000 per MW.

This calculation is performed one time in the Operating Day during which the trigger conditions described in Section 3.6.1 have been met and, subject to the value of the constraint net margin described below, this Shadow Price Cap will remain in effect for the shorter of the remainder of the calendar year or the remainder of the month in which the constraint is determined to be resolvable by SCED.

When the value of a constraint that has met the trigger conditions described in Section 3.6.1 accumulates a net margin, as determined in Section 3.6.3, The Constraint Net Margin Calculation for Constraints that Have Met the Trigger Conditions in Section 3.6.1, below, that exceeds $95,000 /MW at any time during the remainder of the calendar year following the determination that the constraint is irresolvable by SCED, the Shadow Price Cap for this, and for all constraints that have the same overloaded transmission element and direction as the constraint in the next Operating Day will be set to the minimum of either $2,000/MWh or G, below, for the remainder of the calendar year:

G. The Maximum of either the largest value of the Mitigated Offer Cap for Generation Resource C, as determined above, divided by the absolute value of its shift factor on the constraint or the currently effective Low System-Wide Offer Cap (LCAP) pursuant to subsection (g) of P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region.

When a constraint meets the trigger condition described in Section 3.6.1 and accumulates a net margin that exceeds $95,000/MW as described in Section 3.6.2, ERCOT shall:

1. As soon as practicable, but not more than ten (10) business days after the triggers are met, review transmission outages and recall outages that are contributing to overloading the constraint(s), if feasible.
2. As soon as practicable, but not more than thirty (30) days after the triggers are met, review and develop Remedial Action Plans (RAP) or Temporary Outage Action Plans (TOAP) to mitigate congestion on the affected constraint(s), if feasible. To the degree that a RAP or TOAP can be developed, ERCOT shall implement it through an Emergency Database Load, if necessary to avoid delay in addressing the congestion.
3. As soon as practicable, but not more than ninety (90) days after the triggers are met, review and develop or identify one or more Special Protection Systems or transmission proposal(s) to alleviate the risk of future congestion on the affected constraint(s), if feasible, so long as the proposed solution produces an overall reduction of congestion on the ERCOT system.
4. Perform a detailed review of the constraint(s) that is irresolvable by SCED, and in the next annual Regional Transmission Plan, identify projects that will mitigate the risk of future recurrence of the condition, if any.

Additionally, at the end of the calendar year, for all constraints that have a shadow price cap set in accordance with this section, ERCOT will:

- Again determine Generation Resource C and D, as described in item C and D above; and,
- Reset the Shadow Price Cap for each of the SCED irresolvable constraints to the minimum of E or F above for that constraint. These changes shall be become effective in January of the next year.
- Reset the Shadow Price Cap for each constraint determined to be resolvable by SCED to the appropriate generic value as defined in Section 3.5.

The IMM may initiate re-evaluation of the maximum Shadow Price of the constraint if it is identified that the constraint can be resolvable. This will reset the constraint net margin calculation.

3.6.3 The Constraint Net Margin Calculation for Constraints that Have Met the Trigger Conditions in Section 3.6.1

Each constraint that has met the trigger conditions in Section 3.6.1, Trigger for Modification of the Shadow Price Cap for a Constraint that is Consistently Irresolvable in SCED, will be assigned a unique net margin value calculated as follows:

1. The Settlement Point Price at the Resource Node for Generation Resource D (as determined for each SCED irresolvable constraint in Section 3.6.2, Methodology for Setting the Constraint Shadow Price Cap for a Constraint that is Irresolvable by SCED) is designated to be an irresolvable constraint net margin reference SPP. This SPP is unique to each SCED irresolvable constraint.
2. For these, ERCOT will calculate a constraint net margin in \$/MW equal to the running sum of ¼ times the Maximum of either zero or that constraint's (net margin reference SPP – the POC) for all Real Time Settlement Intervals in the current calendar year during which the constraint is binding (i.e. the constraint net margin calculation starts with the first operating day in the current calendar year during which the constraint meets the trigger conditions described in Section 3.6.1).
3. The Proxy Operating Cost (POC) in \$/MWh used in step 2 for each of these constraints equals 10 times the Fuel Index Price as defined in the Protocol Section 2, Definitions and Acronyms, for the Business Day previous to the current Operating Day.
4. All constraint net margin values for these constraints that will be carried to the next calendar year will be reset to zero at the start of the next calendar year and a new running sum will be calculated daily.

4. POWER BALANCE SHADOW PRICE CAP

4.1 The Power Balance Penalty

The Power Balance constraint is the balance between the ERCOT System Load and the amount of generation that is dispatched by SCED to meet that load. This Shadow Price for this constraint, also called System Lambda (λ), is the cost of providing one MWh of energy at the reference Electrical Bus. System Lambda, i.e. the Shadow Price for the Power Balance constraint, is equal to the change in the SCED objective function obtained by relaxing the Power Balance constraint by 1MW. The System Lambda is the energy component of Locational Marginal Price at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this Shadow Price, i.e. Power Balance Penalty is the maximum cost paid for one addition/less MW of generation to meet the ERCOT system load constraint. This section describes those factors that ERCOT considered in developing the amount of the Power Balance Penalty in \$/MW versus the amount of the mismatch and provides the resulting Power Balance Penalty Curve proposed for ERCOT Board approval.

The objective function for SCED is the sum of three components (1) the cost of dispatching generation (2) the penalty for violating Power Balance constraint (3) the penalty for violating network transmission constraints. SCED economically dispatches Generation Resources by minimizing this objective function within the generator physical limits and transmission limits. Since the Power Balance penalty is the maximum cost for meeting the Power Balance, SCED will re-dispatch generation to meet the Power Balance if the cost of re-dispatching the generation is less than cost of violating the Power Balance. When the cost of re-dispatching the Generation Resources becomes higher than the cost of violating the Power Balance constraint, SCED ceases the re-dispatch of the Generation Resources and the objective function is minimized with the Power Balance penalty determined by MW amount of the Power Balance constraint violation.

In the ERCOT design, SCED implements the Power Balance Penalty by a step function with up to 10 (Violation MW; Penalty $/MW) pairs. This curve determines the maximum System Lambda for a given amount of the Power Balance Constraint violation. The following section describes the factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MWh of violation and provides the resulting Power Balance Penalty Curve.

[OBDRR020: Replace Section 4.1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

The Power Balance constraint is the balance between the ERCOT System Load and the amount of generation that is dispatched by SCED to meet that load. This Shadow Price for this constraint, also called System Lambda (λ), is the cost of providing one MWh of energy at the reference Electrical Bus. System Lambda, i.e. the Shadow Price for the Power Balance constraint, is equal to the change in the SCED objective function obtained by relaxing the Power Balance constraint by 1MW. The System Lambda is the energy component of Locational Marginal Price at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this Shadow Price, i.e. Power Balance Penalty is the maximum cost paid for one addition/less MW of generation to meet the ERCOT system load constraint. This section describes those factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MW versus the amount of the mismatch and provides the resulting Power Balance Penalty Price proposed for ERCOT Board approval.

The objective function for SCED is the sum of four components: (1) the cost of dispatching generation; (2) the cost of procuring Ancillary Services; (3) the penalty for violating Power Balance constraint; and (4) the penalty for violating network transmission constraints. SCED economically dispatches Generation Resources and procures Ancillary Services by minimizing this objective function within the generator physical limits and transmission limits. Since the Power Balance penalty is the maximum cost for meeting the Power Balance, SCED will re-dispatch generation to meet the Power Balance if the cost of re-dispatching the generation is less than cost of violating the Power Balance. When the cost of re-dispatching the Generation Resources becomes higher than the cost of violating the Power Balance constraint, SCED ceases the re-dispatch of the Generation Resources and the objective function is minimized with the Power Balance penalty determined by MW amount of the Power Balance constraint violation.

In the ERCOT design, SCED implements the under-generation Power Balance Penalty Price as a single value, which is either (a) $11,000.01/MWh when the Value of Lost Load (VOLL) is equal to the High System-Wide Offer Cap (HCAP), or (b) $4,000.01/MWh when the VOLL is set to the LCAP. This value determines the maximum System Lambda for a given amount of the Power Balance Constraint violation within the optimization. The SCED over-generation Power Balance Penalty Price is -$250/MWh.

4.2 Factors Considered in the Development of the Power Balance Penalty Curve

ERCOT considered a number of factors in the development of the Power Balance Penalty Curve as described below. The dominant factor in the ERCOT qualitative analysis relates to the use of Regulation Ancillary Service capacity in place of generation capacity provided by the market to resolve the SCED Power Balance constraint violation. ERCOT submits that the Power Balance Penalty Curve presented herein represents a reasonable balance between the loss of the Regulation Ancillary Service capacity used to achieve system power balance and the market value of the energy deployed from these Regulation Ancillary Service Generation Resources.

The factors considered by ERCOT in its qualitative analysis, include the following:

- The amount of regulation that can be sacrificed without affecting reliability,
- The PUCT defined System Wide Offer Cap (SWCAP),
- The expected percentage of intervals with SCED Up Ramp scarcity,
- The expected extent of Ancillary Service deployment by operators during intervals with capacity scarcity, and
- The transmission constraint penalty values.

The following discussion describes the details of these factors as they affect the Power Balance Penalty amounts.

Power Balance mismatch occurs whenever SCED is unable to find a dispatch at a cost lower than the Power Balance constraint Penalty. A Power Balance mismatch can occur under two conditions. One condition occurs when the amount of generation that is dispatched up to each resource's High Dispatch Limits is insufficient to meet the system load. This is referred to as an under generation and the System Lambda will be set by the under generation penalty. The opposite occurs when the amount of generation that is dispatched down to each resource's Low Dispatch Limits is greater than the system load. This is referred to as an over generation and the System Lambda will be set by the over generation penalty. Both of these scenarios are unacceptable because, if left uncorrected by regulation, they result in the operation of the ERCOT system below (under generation) or above (over generation) the system frequency set point (nominally 60 Hertz). In the case of under generation, LFC will dispatch additional Regulation Service to correct the condition and restore system frequency to its set point (nominally 60 Hertz). On the other hand, in the case of over generation, LFC will dispatch reduced amounts of Regulation Service to correct the conditions and restore system frequency to its set point (nominally 60 Hertz). In other words, the Power Balance Penalty Curve acts as if it were an energy offer curve for a virtual Generation Resource injecting the amount of the Power Balance mismatch into the ERCOT system.

Since the actions that cause Regulation Ancillary Service capacity to be deployed to meet the Power Balance constraint reduces the amount of regulation capacity that can be used to maintain control of system frequency, the decision of the pricing of the power balance mismatch represents the value of the trade-off between the reduction in system reliability due to the use of the Regulation AS and the cost to the Load Serving Entities. The ERCOT system is particularly vulnerable to an inability to maintain system frequency because of the limited interchange capability of ERCOT with the Western and Eastern interconnects and, therefore, the larger the power balance mismatch, the larger the penalty amount.

In ERCOT, the PUCT has determined a maximum offer cap that is representative of supply side pricing associated with the concept of the value of lost load. By P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, this amount is the High System-Wide Cap and ERCOT selected this amount to serve as the maximum value for the Power Balance Penalty.

Additionally, the Power Balance constraint can also be violated during operational scenarios characterized by generation resource ramp scarcity. SCED calculates dispatch limits (a High Dispatch Limit (HDL) and a Low Dispatch Limit (LDL)) for each resource that represent the amount of dispatch that can be achieved by a Generation Resource at the end of a 5 minute interval at the resource's specified ramp rate given current system conditions and the physical ability of the resource. The ramp rates used in this calculation are referred to as the SCED up Ramp Rate ("SURAMP") and the SCED Down Ramp Rate ("SDRAMP"). A ramp scarcity condition can occur when, for example during morning and evening system ramp intervals, the available capacity for increasing/ decreasing Base Points (the sum of HDL minus current generation/the sum of current generation – LDL) is less than the actual system demand based on the rate at which the system Load is increasing/decreasing. Since the HDL and LDL are calculated based on the physical ramp rate of the resources, they cannot be violated. The likelihood of violation of Power Balance during ramp scarcity increases with the reduction in the capacity available for SCED that in turn depends on the operational philosophies. If Ancillary Services are deployed to maintain enough capacity that can be ramped in each SCED interval then the likelihood of Power Balance violation will be less. On the other hand if Ancillary Services are only deployed to maintain frequency and maintain online capacity and not deployed to maintain enough ramp capacity then the likelihood of Power Balance violation will be more. Along with the violation of the Power Balance Constraint in the over and under generation discussed above, Regulation Ancillary Service will be co-opted in this scenario to compensate for the SCED available capacity shortfall due to these ramp limitations. This scenario is also included in the ERCOT analysis for pricing the Power Balance Penalty.

ERCOT also considered the fact that near scarcity, the Power Balance Constraint can become violated as the result of the network transmission constraints that are also binding/ violated at the same time. In this scenario LMPs will depend on the interaction of the Power Balance Penalty with the network transmission constraint Shadow Price caps (refer to the Appendix description of the SCED Energy LMP calculation to view this relationship). Under such condition the relative values of the network transmission constraint penalty and power balance penalty will determine whether resources with positive Shift Factor on the violated constraints will be moved up to meet Power Balance causing the network transmission constraint to become violated or will be moved down to resolve the network transmission constraint violation with a concomitant Power Balance violation.

Additionally, Protocols limit both the Energy Offer Curves ("EOCs") and the proxy EOC created in SCED to the SWCAP. SCED uses the EOC submitted by a QSE for its Generation Resources subject to the following. A proxy EOC is created in the SCED process if the QSE submitted Energy Offer Curve does not extend from LSL to HSL (in this case SCED extends the submitted EOC as described in Protocol Section 6.5.7.3, Security Constrained Economic Dispatch). A proxy EOC is also created for Generation Resources operating on an Output Schedule. In this case, the proxy EOC is designed to limit the dispatch of these resources from their Output Schedule amounts by pricing this dispatch at values equal to the System-Wide floor or cap. Since the Power Balance Penalty curve can be characterized as equivalent to a virtual EOC, the relative value of the Power Balance Penalty to the EOCs used by SCED will determine whether the energy will be deployed from the EOC or the Power Balance Penalty curve. If the Power Balance constraint is violated in step one of SCED, then the Power Balance Penalty will set the reference LMP and the submitted and proxy EOCs will then be mitigated at the max of that reference LMP or verifiable cost in the second step of SCED. Consequently, if the Power Balance Penalty Curve provides a gradual ramp to SWCAP then the prices will gradually ramp to the SWCAP instead experiencing a sudden jump to SWCAP.

[OBDRR020: Delete Section 4.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project:]

4.3 The ERCOT Power Balance Penalty Curve

Based on the criteria described in Section 4.2, Factors Considered in the Development of the Power Balance Penalty Curve, above, the SCED under-generation Power Balance Penalty is shown in Figure 4. The SCED over-generation Power Balance Penalty curve will be set to System-Wide Offer Floor.

SCED Under-generation Power Balance Penalty Curve

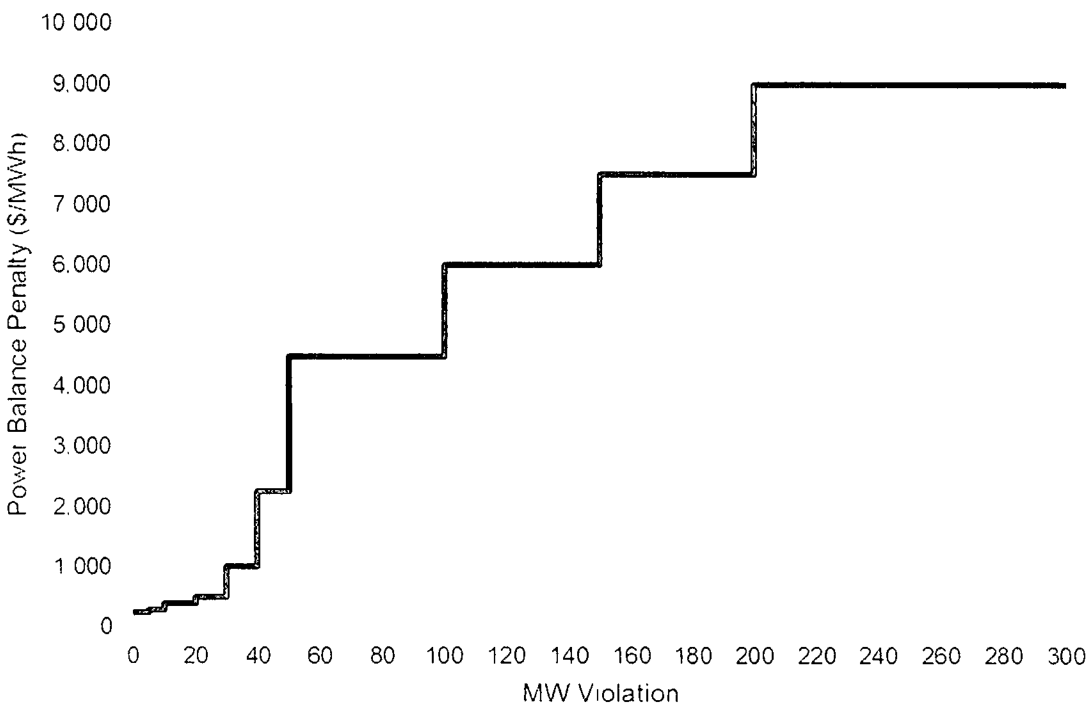


Figure 4

MW Violation	*Penalty Value ($/MWh)*
≤ 5	250
5 < to ≤ 10	300
10 < to ≤ 20	400
20 < to ≤ 30	500
30 < to ≤ 40	1,000
40 < to ≤ 50	2,250
50 < to ≤ 100	4,500
100 < to ≤ 150	6,000
150 < to ≤ 200	7,500
200 or more	9,001

The SCED under-generation Power Balance Penalty curve will be capped at LCAP plus $1 per MWh whenever the SWCAP is set to the LCAP.

SCED Over-generation Power Balance Penalty Curve

MW Violation	*Penalty Value ($/MWh)*
< 100,000	**-250**

[OBDRR020: Delete Section 4.3 above upon system implementation of the Real-Time Co-Optimization (RTC) project:]

APPENDIX 1: THE SCED OPTIMIZATION OBJECTIVE FUNCTION AND CONSTRAINTS

The SCED optimization objective function is as given by the following:

Minimize {Cost of dispatching generation
+ Penalty for violating Power Balance constraint
+ Penalty for violating transmission constraints}

which is:

Minimize {sum of (offer price * MW dispatched)
+ sum (Penalty * Power Balance violation MW amount)
+ sum (Penalty *Transmission constraint violation MW amount)}

The objective is subject to the following constraints:

- Power Balance Constraint
  sum (Base Point) + under gen slack – over gen slack = Generation To Be Dispatched
- Transmission Constraints
  sum(Shift Factor * Base Point) – violation slack $\leq$ limit
- Dispatch Limits
  LDL $\leq$ Base Point $\leq$ HDL

Based on the SCED dispatch the LMP at each Electrical Bus is calculated as

$$LMP_{bus,t} = SP_{demand,t} - \sum_{c} SF_{bus,c,t} \cdot SP_{c;t}$$

Where

$SP_{demand,t}$ = System Lambda or Power Balance Penalty (if a Power Balance violation exists) at time interval "t"

$SF_{bus,c,t}$ = Shift Factor impact of the bus "bus" on constraint "c" at time interval "t"

$SP_{c,t}$ = Shadow Price of constraint "c" at time interval "t" (capped at Max Shadow Price for this constraint).

During scarcity if a transmission constraint is violated then transmission constraint and Power Balance constraint will interact with each other to determine whether to move up or move down a resource with positive SF to the violated constraints if there are no other resources available.

(a) Cost of moving up the Resource = Shift Factor * Transmission Constraint Penalty + Offer cost
(b) Cost of moving down the Resource = Power Balance Penalty

The Resource will be moved down for resolving constraints if (a) > (b).
If (a) < (b) then the Resource will be moved up for meeting Power Balance.

[OBDRR020: Delete Appendix 1 above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]

APPENDIX 2: DAY-AHEAD MARKET OPTIMIZATION CONTROL PARAMETERS

The purpose of the Day-Ahead Market (DAM) is to economically co-optimize energy and Ancillary Service by simultaneously clearing offers and bids submitted by the Market Participants to maximize social welfare while observing the transmission and generation physical constraints. The ERCOT DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to transmission security and other constraints as described in Protocol Section 4, Day-Ahead Operations. The bid-based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation Bids. The Offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of Resources that submitted a Three-Part Supply Offer, as well as the DAM Energy-Only Offers, CRR Offers, and Ancillary Service Offers. The DAM optimization's objective function includes components that represent the bid based revenues and offer based cost and, additionally, penalty cost values that are used to control certain non-economic aspects of the optimization as described below. These penalty values represent costs of constraint violations and they serve two purposes: rank constraints as relative violation priorities and limit the costs of constraint limitations. Based on paragraph (4)(c)(i) of Protocol Section 4.5.1, DAM Clearing Process, the transmission constraint limits needs to be satisfied in DAM and hence the transmission constraint penalty values are set to very high values to ensure that the constraints are not violated in DAM.

[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

The purpose of the Day-Ahead Market (DAM) is to economically co-optimize energy and Ancillary Service by simultaneously clearing offers and bids submitted by the Market Participants to maximize social welfare while observing the transmission and generation physical constraints. The ERCOT DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to transmission security and other constraints as described in Protocol Section 4, Day-Ahead Operations. The bid-based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation Bids. The Offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of Resources that submitted a Three-

Part Supply Offer, as well as the DAM Energy-Only Offers, CRR Offers, and Ancillary Service Offers. The DAM optimization's objective function includes components that represent the bid based revenues and offer based cost and, additionally, penalty cost values that are used to control certain non-economic aspects of the optimization as described below. These penalty values represent costs of constraint violations and they serve two purposes: rank constraints as relative violation priorities and limit the costs of constraint limitations. The Protocols require transmission constraint limits to be satisfied in DAM and hence the transmission constraint penalty values are set to very high values to ensure that the constraints are not violated in DAM. The DAM optimization will also consider Ancillary Service Demand Curves for each Ancillary Service product.

The penalty factors used in the Day-Ahead optimization's objective function are configurable and can be set by an authorized ERCOT Operator. Table 2-1 lists the available optimization penalty cost parameters that are controllable by the ERCOT Operator. The values provided for each of these parameters have been determined by ERCOT based on the results of the DAM quality of solution analysis and various DAM stress tests performed by ERCOT and, following the TNMID, may only be changed with the concurrence of the responsible ERCOT Director.

[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]   The penalty factors used in the DAM optimization's objective function are configurable and can be set by an authorized ERCOT Operator. Table 1-1 lists the available optimization penalty cost parameters that are controllable by the ERCOT Operator. The values provided for each of these parameters may only be changed with the concurrence of the responsible ERCOT Director.

TABLE 2 - 1

Penalty Function & Shadow Price Cap Cost Parameters	
Constraint	Penalty ($/MWh)
Over and Under - Generation Penalty Factors	
Over Generation	5,000,000.00
Under Generation	5,000,000.00
Ancillary Service Penalty Factors	
Regulation Down	SWCAP~~3,000,000.00~~
Regulation Up	SWCAP~~3,000,000.00~~
Responsive Reserve	SWCAP minus 0.01~~2,000,000.00~~
Non-spin Reserve	SWCAP minus 0.03~~1,000,000.00~~
Network Transmission Penalty Factors	
Base case 1-10KV	350,000.00
Base case 10.1-20KV	450,000.00
Base case 20.1-30KV	550,000.00
Base case 30.1-50KV	650,000.00
Base case 50.1-100KV	750,000.00
Base case 100.1-120KV	850,000.00
Base case 120.1-150KV	950,000.00
Base case 150+KV	1,050,000.00
Contingency 1-10KV	300,000.00
Contingency 10.1-20KV	400,000.00
Contingency 20.1-30KV	500,000.00
Contingency 30.1-50KV	600,000.00
Contingency 50.1-100KV	700,000.00
Contingency 100.1-120KV	800,000.00
Contingency 120.1-150KV	900,000.00
Contingency 150+KV	1,000,000.00
Non-thermal (e.g. generic constraints)	1,000,000.00

[OBDRR020: Replace the Table 2-1 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

TABLE 1 - 2~~1~~

Penalty Function & Shadow Price Cap Cost Parameters	
Constraint	Penalty ($/MWh)
Over and Under - Generation Penalty Factors	
Over Generation	5,000,000.00
Under Generation	5,000,000.00

Network Transmission Penalty Factors	
Base case 1-10KV	350,000.00
Base case 10.1-20KV	450,000.00
Base case 20.1-30KV	550,000.00
Base case 30.1-50KV	650,000.00
Base case 50.1-100KV	750,000.00
Base case 100.1-120KV	850,000.00
Base case 120.1-150KV	950,000.00
Base case 150+KV	1,050,000.00
Contingency 1-10KV	300,000.00
Contingency 10.1-20KV	400,000.00
Contingency 20.1-30KV	500,000.00
Contingency 30.1-50KV	600,000.00
Contingency 50.1-100KV	700,000.00
Contingency 100.1-120KV	800,000.00
Contingency 120.1-150KV	900,000.00
Contingency 150+KV	1,000,000.00
Non-thermal (e.g. generic constraints)	1,000,000.00

2.1 Over/Under – Generation Penalty Factors

In the ERCOT DAM an over/under energy supply condition (referred to here as over/under generation conditions) in an Operating Hour within the Operating Day can occur as a result of a strike of energy only block offers or the inherent lumpiness of Generation Resource strikes. The values of the Over/Under Generation Penalty Factors are chosen to allow the DAM clearing engine to select offers that result in the least amount of the over/under generation over the entire Operating Day and additionally, to enforce this constraint at the highest rank order relative to all other constraints. Additionally, the values of the Over/Under Generation Penalty Factors used in the DAM are considerably higher than the Power Balance Penalty Factor used in the SCED since DAM is a unit commitment problem and for it to clear reasonable offers and bids, the value of these penalty factors need to be high enough to reflect the start up and minimum generation cost of the committed resources. SCED, on the other hand, is an economic dispatch problem and hence for it to dispatch reasonable offers, the Power Balance Penalty Factor need only be in the order of the energy offer cost.

2.2 Ancillary Service Penalty Factors

The Ancillary Service penalty factors serve two purposes. The procured amount of an Ancillary Service can be lower than the difference between the amount of the required AS, as specified in the AS Plan, and the amount of the self-arranged AS. The value of the AS penalty factors are chosen to allow the selection of AS offers that result in the least amount of deficit considering the maximum AS penalty factors referenced in Appendix 2, Table 2-1 for each given AS over the Operating Day and to assign a priority to the AS constraints relative to the enforcement of the Power Balance and Network Transmission constraints. Additionally, the increasing penalty cost structure from Non-Spin AS to Regulation AS prioritizes the DAM AS procurement as first Regulation Services, then Responsive Reserve Service and lastly Non-Spin Service. In other words multiple offers from the same resource will be considered in the rank order given. 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. The AS penalty factors used in DAM are also used in the Supplemental Ancillary Service Market (SASM) engine.

[OBDRR020: Delete Section 2.2 above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]

2.3 Network Transmission Penalty Factors

The DAM Clearing Engine includes the Network Security Monitor (NSM) application and Network Constrained Unit Commitment (NCUC) application. These applications execute in a loop beginning with a NSM execution followed by a NCUC execution until a secure commitment pattern that maximizes the objective function is achieved (i.e. NSM begins with an estimated initial unit commitment and uses, thereafter, the latest NCUC commitment). The value of the Network Transmission Penalty Factors for each specified voltage level are used in NCUC application to set the rank order for relaxing the base case constraints and the security constrained network transmission constraints by voltage level and to set the rank order for the enforcement of the Network Transmission Constraints relative to the Power Balance and AS requirements. The increasing value of the Network Transmission Penalty Factors for increasing voltage levels assures that base case and security constraint violations are relaxed progressively in the NSM and NCUC applications in order of voltage level, from lowest to highest. This assures that the DAM solution will honor network transmission constraints in the rank order from the 345 kV to the 69 kV voltage level. Additionally, these penalty factors are chosen such that, in each voltage range, the base case violations have a slightly higher penalty factor than the security constrained penalty factors. This assigns a higher priority in the NSM and NCUC to a network transmission base case violation compared to a network transmission security constrained violation. In other words, within the same voltage level, the security constraints are relaxed before the base case constraints.
Finally, the Non-Thermal (generic constraint) Penalty Factor assigns these constraints the same priority level in the optimization as the 345 kV security constraints making both less than the 345 kV base case constraints.

[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

The DAM Clearing Engine includes the Network Security Monitor (NSM) application and Network Constrained Unit Commitment (NCUC) application. These applications execute in a loop beginning with a NSM execution followed by a NCUC execution until a secure commitment pattern that maximizes the objective function is achieved (i.e. NSM begins with an estimated initial unit commitment and uses, thereafter, the latest NCUC commitment). The value of the Network Transmission Penalty Factors for each specified voltage level are used in NCUC application to set the rank order for relaxing the base case constraints and the security constrained network transmission constraints by voltage level and to set the rank order for the enforcement of the Network Transmission Constraints relative to the Power Balance constraint. The increasing value of the Network Transmission Penalty Factors for increasing voltage levels assures that base case and security constraint violations are relaxed progressively in the NSM and NCUC applications in order of voltage level, from lowest to highest. This assures that the DAM solution will honor network transmission constraints in the rank order from the 345 kV to the 69 kV voltage level. Additionally, these penalty factors are chosen such that, in each voltage range, the base case violations have a slightly higher penalty factor than the security constrained penalty factors. This assigns a higher priority in the NSM and NCUC to a network transmission base case violation compared to a network transmission security constrained violation. In other words, within the same voltage level, the security constraints are relaxed before the base case constraints. Finally, the Non-Thermal (generic constraint) Penalty Factor assigns these constraints the same priority level in the optimization as the 345 kV security constraints making both less than the 345 kV base case constraints.

The values of the Network Transmission Penalty Factors chosen to enforce the Network Transmission Constraints are considerably higher in DAM when compared to the SCED (Network Transmission Shadow Price Caps) since the DAM is a unit commitment problem and for it to clear reasonable offers and bids, the Network Transmission Penalty Factors need to represent the higher costs associated with a unit start up and generation at minimum energy. The SCED is an economic dispatch problem and hence for it to dispatch reasonable offers; the penalties need only be in the order of energy offer cost.

ERCOT Impact Analysis Report

OBDRR Number	030	OBDRR Title	Related to NPRR1080, Ancillary Service Price Cap
Impact Analysis Date	June 3, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Other Binding Document Revision Request (OBDRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1080, Ancillary Service Price Cap.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
There are no additional impacts to this OBDRR beyond what was captured in the Impact Analysis for NPRR1080.

TAC Report

OBDRR Number	031	OBDRR Title	Change Non-Spinning Reserve Service Deployment
Date of Decision	June 30, 2021		
Action	Approved		
Effective Date	July 1, 2021		
Priority and Rank Assigned	Not applicable		
Other Binding Document Requiring Revision	Non-Spinning Reserve Service Deployment and Recall Procedure		
Supporting Protocol or Guide Section(s) / Related Documents	Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment		
Revision Description	This Other Binding Document Revision Request (OBDRR) makes two changes to Non-Spinning Reserve (Non-Spin) deployment to enhance Texas grid reliability. First, it changes the calculation for deploying Non-Spin currently based on High Ancillary Service Limit (HASL) less Generation less the forecasted 30-minute load ramp. The calculation is changed such that it includes Intermittent Renewable Resource (IRR) curtailment, which can often be several GW and can thus significantly affect the amount of generation that can be dispatched. It also changes the 30-minute load ramp to be 30-minute net load ramp, a more accurate measure of system generation dispatch need. Second, a new deployment condition is added when Physical Responsive Capability (PRC) is below 3,200 MW and is not expected to recover within 30 minutes. This will allow operators to deploy Non-Spin in advance of a potential Emergency Condition. A corresponding change in the recall of Non-Spin is also made.		
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	This OBDRR changes the calculation of the deployment threshold for Non-Spin to reflect system need more accurately. It also gives operators the ability to deploy Non-Spin earlier, thereby reducing the likelihood of entering into Emergency Conditions. These changes should enhance Texas grid reliability.
TAC Decision	On 6/30/21, TAC voted via roll call to approve OBDRR031 as submitted. There were two opposing votes from the Independent Retail Electric Provider (IREP) (Just Energy and Demand Control 2) Market Segment and two abstentions from the Independent Generator (Luminant and Calpine) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/30/21, ERCOT Staff provided an overview of OBDRR031 and the reliability need for a more conservative approach to procuring Ancillary Services moving forward. Participants noted increased Non-Spin levels would likely reduce the need for Reliability Unit Commitment (RUC) activity. Some participants voiced support for the conservative approach, particularly in the short term, but expressed hedging concerns related to the magnitude of the MW changes and potential pricing impacts over the long term. Other participants questioned making any significant procurement changes for this summer, requested additional analysis of the issues raised, and suggested waiting until after the summer before moving forward with any changes. Participants raised the prospect of a subsequent OBDRR later this year to revise the MW levels and variables within this Other Binding Document based on analysis of the summer. TAC leadership directed the Wholesale Market Subcommittee (WMS) and Reliability and Operations Subcommittee (ROS) to continue to review the issues raised along with the impacts of OBDRR031 and return to the October 27, 2021 TAC meeting with recommendations.

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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Other Binding Document Language Revision

1. Nodal Market Non-Spinning Reserve Service Deployment and Recall Procedure

For any Non-Spinning Reserve (Non-Spin) Service that is not continually deployed to Security-Constrained Economic Dispatch (SCED) as part of a standing On-Line Non-Spin deployment, there are four situations that will cause Non-Spin to be deployed:

- Detection of insufficient capacity for energy dispatch during periodic checking of available capacity.
- Disturbance conditions such as a unit trip, sustained frequency decay or sustained low frequency operations.
- SCED not having enough energy available to execute successfully.
- When Off-Line Generation Resource providing Non-Spin are the only reasonable option available to the Operator for resolving local issues.

In each of these cases, the ERCOT operator will make the final decision and initiate the deployment. The ERCOT operator shall deploy Non-Spin in amounts sufficient to respond to the operational circumstances. This means that Non-Spin may be deployed partially over time or may be deployed in its entirety. If Non-Spin is deployed partially, it shall be deployed in increments of 100% of each Resource's capacity. To support partial deployment, ERCOT shall, following the Day-Ahead Market (DAM), rank, for each hour of the Operating Day, the Resources supplying Non-Spin in an economic order based on DAM Settlement Point Prices. Partial Non-Spin deployment and recall decisions shall be based on each Resource's economic cost order.

2. Non-Spin Deployment

ERCOT may deploy Non-Spin, which has not been deployed as part of a standing On-Line Non-Spin deployment, under the following conditions:

- When (HASL – Gen) – (30-minute load ramp) < 0 MW, deploy half of the available Non-Spin capacity.
- When (HASL – Gen) – (30-minute load ramp) < -300 MW, deploy all of the available Non-Spin capacity.

[OBDRR031: Replace the language above with the following on August 2, 2021:]

- When (HASL – Gen – Intermittent Renewable Resource (IRR) Curtailment) – (30-minute net load ramp) < 0 MW, deploy half of the available Non-Spin capacity.
- When (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) < -300 MW, deploy all of the available Non-Spin capacity.

[OBDRR031: Insert the language below on July 12, 2021:]

- When PRC < 3200 MW and not expected to recover within 30 minutes without deploying reserves, deploy all or a portion of the available Non-Spin capacity.

- When PRC < 2500 MW, deploy all of the available Non-Spin capacity.
- When the North-to-Houston (N_H) Voltage Stability Limit Reliability Margin < 300 MW, deploy Non-Spin (all or partial) in the Houston area as needed to restore reliability margin.
- When Off-Line Generation Resources providing Non-Spin are the only reasonable option available to the Operator for resolving local issues, deploy available Non-Spin capacity on only the necessary individual Resources.

If a condition other than those listed above indicates that additional capacity may need to be brought On-Line to manage reliability, operators will evaluate the system condition and deploy Non-Spin as needed if no other better options are available to resolve the system condition. Under emergency, the emergency process will govern the deployment of Non-Spin.

Following a Non-spin deployment, the following steps should be taken:

2.1. Off-Line Generation Resource reserved for Non-Spin

- The QSE will be sent a Resource-specific Dispatch Instruction that Non-Spin has been deployed.
- The Dispatch Instruction must include the expected amount of *capacity* that will be available for SCED and the anticipated duration of the deployment.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that unit has been reduced to zero within 20 minutes of the Dispatch Instruction.
- The QSE must have the Resource On-Line with an Energy Offer Curve and the telemetered net generation must be greater than or equal to the Resource's

telemetered LSL multiplied by P1 where P1 is defined in the "ERCOT and QSE Operations Business Practices During the Operating Hour" within 25 minutes of the Dispatch Instruction.

- SCED will respond to the changes in Resource Status that are received by telemetry from the QSE.
- Once the Resource is On-Line it is Dispatched as any other Generation Resource including any provisions for processing generation less than the Resource's LSL.
- The Resource must, at a minimum, be capable of providing all the Non-Spin energy to SCED within 30 minutes of the Dispatch Instruction.

2.2. <u>On-Line Generation Resource with an Energy Offer Curve</u>

- For a Resource that *will not use power augmentation* to provide any portion of its Non-Spin Ancillary Service Resource Responsibility:
  - The QSE shall set the value of the Non-Spin Ancillary Service Schedule to zero within the 30-second window prior to the start of the delivery hour.
  - ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
  - The total amount of capacity reserved on that Resource for Non-Spin shall be considered as a standing Non-Spin deployment Dispatch Instruction for the duration of the Operating Hour.
  - A Non-Spin deployment Dispatch Instruction from ERCOT is not required for standing Non-Spin deployments.
- For a Resource that *will use power augmentation* to provide a specific MW portion of its Non-Spin Ancillary Service Responsibility:
  - The QSE shall set the value of the Non-Spin Ancillary Service Schedule to the appropriate value within the 30-second window prior to the start of the delivery hour.
  - The QSE may set the value of the Non-Spin Ancillary Service Schedule equal to the MW amount of Non-Spin that will be provided via power. augmentation; otherwise, the QSE may set the value of the schedule to zero.
  - If the Non-Spin Ancillary Service Schedule is set to zero, then the total amount of capacity reserved on that Resource for Non-Spin shall be considered as a standing Non-Spin deployment Dispatch Instruction for the duration of the Operating Hour.
  - If the Non-Spin Ancillary Service Schedule is set to a non-zero value, then the QSE will be sent a Resource-specific Dispatch Instruction indicating that Non-Spin has been deployed for the total amount of the Non-Spin Schedule.
    - The Dispatch Instruction must include the expected amount of *capacity* that will be available for SCED and the anticipated duration of the deployment.

        - The QSE shall reduce the Resource's Non-Spin Ancillary Service Schedule to zero within 20 minutes following a deployment instruction.
    - ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- The QSE must, at a minimum, ensure that the Normal Ramp Rate represented by the Resource's ramp rate curve is sufficient to allow SCED to fully Dispatch the Resource's Non-Spin Resource Responsibility within 30 minutes, regardless of whether or not the Resource uses power augmentation to provide the service.

2.3. <u>On-Line Generation Resource with Output Schedules</u>

- The QSE shall set the value of the Non-Spin Ancillary Service Schedule to zero within the 30-second window prior to the start of the delivery hour.
- ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- If the QSE is sent a Resource-specific Dispatch Instruction indicating that Non-Spin has been deployed:
    - The Dispatch Instruction must include the additional amount of *energy* (MW) that needs to be produced by the Resource and the estimated duration of the deployment.
    - For DSRs providing Non-Spin, as soon as the QSE receives the deployment, the QSE shall adjust the telemetry Output Schedule to reflect the Non-Spin deployment. A DSR QSE with a Load Resource that has provided Non-Spin will ensure that the Output Schedule is not reduced to reflect the Load deployment if the Load Resource is part of the DSR Load that the Resource follows.
    - For non-DSRs (with Output Schedules) providing Non-Spin, ERCOT shall increase the Output Schedule used in SCED by the difference between telemetered Non-Spin Ancillary Service Resource Responsibility and Ancillary Service Schedule to reflect the amount of Non-Spin energy that is to be provided by the Resource in response to the Non-Spin deployment.

2.4 <u>Controllable Load Resource with Non-Spin Ancillary Service Resource Responsibility</u>

- The QSE will be sent a Resource-specific Dispatch Instruction that Non-Spin has been deployed.
- The Dispatch Instruction must include the expected amount of capacity that will be available for SCED and the anticipated duration of the deployment.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that Controllable Load Resource has been reduced to zero within 20 minutes of the Dispatch Instruction.

- The QSE must have the Controllable Load Resource's telemetered Resource Status as On-Line (ONRGL and/or ONCLR, whichever is applicable) with an RTM Energy Bid, and the Controllable Load Resource's telemetered net real power consumption must be greater than or equal to the Controllable Load Resource's telemetered LPC plus its total upward Ancillary Service Resource Responsibility.
- ERCOT will automatically calculate new LASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- Once the Controllable Load Resource's Non-Spin capacity has been released to SCED, this capacity is Dispatched as any other Resource available to SCED.
- The Controllable Load Resource must, at a minimum, be capable of providing all the Non-Spin energy to SCED within 30 minutes of the Dispatch Instruction.

3. Recall of Non-Spin Deployment

Half of the deployed Non-Spin will be recalled when (HASL – Gen) – (30-minute load ramp) > 1000 MW and PRC is > 2800 MW. All of the deployed Non-Spin will be recalled when (HASL – Gen) – (30-minute load ramp) > 1000 MW and PRC is > 3000 MW.

[OBDRR031: Replace the language above with the following on July 12, 2021:]

Half of the deployed Non-Spin may be recalled when (HASL – Gen) – (30-minute load ramp) > 1000 MW and PRC is > 3200 MW. All of the deployed Non-Spin may be recalled when (HASL – Gen) – (30-minute load ramp) > 1000 MW and PRC is > 3400 MW.

[OBDRR031: Replace the language above with the following on August 2, 2021:]

Half of the deployed Non-Spin may be recalled when (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) > 1000 MW and PRC is > 3200 MW. All of the deployed Non-Spin may be recalled when (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) > 1000 MW and PRC is > 3400 MW.

Following the recall of a Non-spin deployment, the following steps should be taken:

- After recall, the QSE for a Generation Resource will be allowed to use normal shutdown procedures to take the Generation Resource Off-Line if the QSE wants to shut down the Resource. In this case, the Non-Spin Ancillary Service Schedule for that Generation Resource will be reset to equal the Non-Spin Ancillary Service Responsibility for that Generation Resource for that hour. A QSE with a Generation Resource that was previously Off-Line will be allowed to keep the Generation Resource On-Line after the minimum On-Line time, provided that the difference between its HSL and LSL is greater than or equal to its Ancillary Service Resource Responsibility.

- A QSE with a Generation Resource (with an Energy Offer Curve) that will stay On-Line may set the value of the Non-Spin Ancillary Service Schedule equal to the MW amount of Non-Spin that will be provided via power augmentation; otherwise, the QSE will ensure that the value of the Non-Spin Ancillary Service Schedule for that Resource is set to 0 MW.
- A QSE with a DSR Generation Resource (with an Output Schedule) that will stay On-Line will back out the Non-Spin addition that was made to the Output Schedule. This can be incrementally deleted depending on the size of the deployment and Normal Ramp Rate. For non-DSR Generation Resources, SCED will use the QSE submitted non-DSR Output Schedule once the Non-Spin has been recalled.
- A QSE with a Controllable Load Resource that has provided Non-Spin will ensure that the Load energy and Non-Spin capability is restored within three hours from the expiration of the Non-Spin deployment. If it is not, the Non-Spin capability must be replaced by the QSE on other Generation or Controllable Load Resources capable of providing the service.

If Non-Spin has been deployed in the Houston area to help manage the N_H Voltage Stability Limit, the deployments will be recalled once reliability margins have been restored to a manageable level.

4. Non-Spinning Reserve Service Deployment and Recall Procedure Revision Process

Revisions to the Non-Spinning Reserve Service Deployment and Recall Procedure shall be made according to the approval process as prescribed in Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.

ERCOT Impact Analysis Report

OBDRR Number	031	OBDRR Title	Change Non-Spinning Reserve Service Deployment
Impact Analysis Date	June 24, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Other Binding Document Revision Request (OBDRR) can take effect upon Technical Advisory Committee (TAC) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this OBDRR.		
Grid Operations & Practices Impacts	ERCOT will update grid operations and practices to implement this OBDRR.		

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.