Variable	Unit	Definition
$ESRELCC_{p, \cancel{d}, s, i}$	%	*Effective Load Carrying Capability (ELCC) for Energy Storage Resources (ESRs)*—The average ~~annual~~ ELCC for Reserve Risk Period *p*, ~~Duration Class *d*,~~ Season *s*, and Year *i*, expressed as a percentage.
$ESRCAP_{p, \cancel{d}, s, i}$	%	*Available ESR Capacity*—The amount of ESR capacity by Reserve Risk Period p, ~~Duration Class *d*,~~ Season *s*, and Year i that is currently operational, multiplied by $ESRELCC_{p, r, s, i}$. Capacity is considered operational if it has an ERCOT Resource Commissioning Date or ERCOT has approved, or expects to approve, the capacity for grid synchronization by the start of Season *s* for Year *i*. For ESRs classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1, capacity is considered operational once a Model Ready Date has been assigned to the resource.
$RMRCAP_{s, i}$	MW	*Seasonal Net Max Sustainable Rating for Generation Resource providing RMR Service*—The Seasonal net maximum sustainable rating for Season *s* as reported in the RIOO system for each Generation Resource providing RMR Service for the Year *i* until the approved exit strategy for the RMR Resource is expected to be completed.
$DCTIEPEAKPCT_{s}$	%	*Seasonal Net Import Capacity for existing DC Tie Resources as a Percent of Installed DC Tie Capacity*—The average net emergency DC Tie imports for Season *s*, divided by the total installed DC Tie capacity for Season *s*, expressed as a percentage. The average net emergency DC Tie imports is calculated for the SCED intervals during which ERCOT declared an Energy Emergency Alert (EEA). This calculation is limited to the most recent Seasons in which an EEA was declared. For the spring and fall seasons ERCOT will use the winter and summer values, respectively, if no EEA events have occurred for these seasons. The total installed DC Tie capacity is the capacity amount at the start of the Seasons used for calculating the net DC Tie imports.
$DCTIECAP_{s}$	MW	*Expected Existing DC Tie Capacity Available under Emergency Conditions*—$DCTIEPEAKPCT_{s}$ multiplied by the installed DC Tie capacity available for Season *s*, adjusted for any known capacity transfer limitations.
$PLANDCTIECAP_{s}$	MW	*Expected Planned DC Tie Capacity Available under Emergency Conditions*—$DCTIEPEAKPCT_{s}$ multiplied by the maximum peak import capacity of planned DC Tie projects included in the most recent Steady State Working Group (SSWG) base cases, for Season *s*. The import capacity may be adjusted to reflect known capacity transfer limitations indicated by transmission studies.
$SWITCHCAP_{s, i}$	MW	*Seasonal Net Max Sustainable Rating for Switchable Generation Resources*—The Seasonal net maximum sustainable rating for Season *s* as reported in the RIOO system for each Generation Resource for Year *i* that can electrically connect (i.e., "switch") from the ERCOT Region to another power region.

Variable	Unit	Definition
$MOTHCAP_{s,i}$	MW	*Seasonal Net Max Sustainable Rating for Mothballed Generation Resource*—The Seasonal net maximum sustainable rating for Season *s* as reported in the RIOO system for each Mothballed Generation Resource for y Year *i* based on the lead time and probability information furnished by the owners of Mothballed Generation Resources pursuant to Section 3.14.1.9, Generation Resource Status Updates. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is greater than or equal to 75%, then use the Seasonal net maximum sustainable rating for Season *s* as reported in the RIOO system for the Mothballed Generation Resource for Year *i*. If the value furnished by the owner of a Mothballed Generation Resource pursuant to Section 3.14.1.9 is less than 75%, then exclude that Resource from the Total Capacity Estimate.
$PLANTHERMCAP_{s,i}$	MW	*New Thermal Generating Capacity*—The amount of new thermal generating capacity available by the start of Season s and Year *i* that: (a) has a Texas Commission on Environmental Quality (TCEQ)-approved air permit, (b) has a federal Greenhouse Gas permit, if required, (c) has obtained water rights, contracts or groundwater supplies sufficient for the generation of electricity at the Resource, (d) has a signed Standard Generation Interconnection Agreement (SGIA), or a public, financially-binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed; or for a Municipally Owned Utility (MOU) or Electric Cooperative (EC), a public commitment letter to construct a new Resource, (e) a written notice from the TSP that the Interconnecting Entity has provided notice to proceed with the construction of the interconnection, and (f) provided the TSP with sufficient financial security to fund the interconnection facilities. New, Thermal generating capacity is excluded if the Generation Interconnection or Modification (GIM) project status in the RIOO interconnection services system is set to "Cancelled" or "Inactive" or if the Resource was previously mothballed or retired and does not have an owner that intends to operate it. For the purposes of this section, ownership of a mothballed or retired Resource for which a new generation interconnection is sought can only be satisfied by proof of site control as described in paragraph (1)(a), (b), or (d) of Planning Guide Section 5.3.2.1, Proof of Site Control. Thermal resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1 must have an ERCOT-assigned Model Ready Date.
$PLANWINDCAP_{p,s,i,wr}$		*New WGR Capacity*—For new WGRs, the capacity available by the start of Season *s*, Reserve Risk Period *p*, Year *i*, and region *wr*, multiplied by WINDELCC for season *s* for Reserve Risk Period *p*, year *i*, and Region *wr*. New WGRs must have (1) an SGIA or other public, financially binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed or, for a MOU or EC, a public commitment letter to construct a new WGR, (2) a written notice from the TSP that the IE has provided notice to proceed with the construction of the interconnection, and (3) provided the TSP with sufficient financial security to fund the interconnection facilities. Wind resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1 must have an ERCOT-assigned Model Ready Date.

Variable	Unit	Definition
PLANSOLARCAP $_{p,\ s,\ i,\ sr}$		*New PVGR Capacity*—For new PVGRs, the capacity available by the start of season *s* for Risk Period *p*, Year *i*, and region *sr*, multiplied by SOLARELCC $_{p,\ s,\ i,\ sr}$. New PVGRs must have (1) an SGIA or other public, financially binding agreement between the Resource owner and TSP under which generation interconnection facilities would be constructed or, for a MOU or EC, a public commitment letter to construct a new WGR, (2) a written notice from the TSP that the IE has provided notice to proceed with the construction of the interconnection, and (3) provided the TSP with sufficient financial security to fund the interconnection facilities. Solar resources classified as small generators in accordance with paragraph (3) of Planning Guide Section 5.2.1 must have an ERCOT-assigned Model Ready Date.
PLANESRCAP $_{p,\ s,\ i}$	MW	*Available Energy Storage Resource Capacity*—The amount of ESR capacity that ERCOT has approved, or expects to approve, for grid synchronization by the start of season *s* for Reserve Risk Period *p* and Year *i*, multiplied by ERSELCC $_{p,\ s,\ i}$.
LTOUTAGE $_{s,\ i}$	MW	*Forced Outage Capacity Reported in a Notification of Suspension of Operations*—For Generation Resources whose operation has been suspended due to a Forced Outage as reported in a Notification of Suspension of Operations (NSO), the sum of Seasonal net maximum sustainable ratings for Season *s* and Year *i*, as reported in the NSO forms. For Inverter Based Resources use WINDCAP, SOLARCAP, and ESRCAP rather than ratings reported in NSOs.
UNSWITCH $_{s,\ i}$	MW	*Capacity of Unavailable Switchable Generation Resource*—The amount of capacity reported by the owners of a switchable Generation Resource that will be unavailable to ERCOT during Season *s* and Year *i* pursuant to paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information.
RETCAPNSO $_{s,\ i}$	MW	*Capacity Pending Retirement*—The amount of capacity in Season *s* of Year *i* that is pending retirement based on information submitted on an NSO form (Section 22, Attachment E, Notification of Suspension of Operations) pursuant to Section 3.14.1.11, Budgeting Eligible Costs, but is under review by ERCOT pursuant to Section 3.14.1.2, ERCOT Evaluation Process, that has not otherwise been considered in any of the above defined categories. For Generation Resources and SOGs within Private Use Networks, the retired capacity amount is deducted from PUNCAP.
RETCAPUNC $_{s,\ i}$	MW	*Unconfirmed Planned Retirements*—The capacity of Generation Resources for which a public announcement of the intent to permanently shut the unit down has been released, but a Notice of Suspension of Operations for the unit has not been received by ERCOT. To be considered an Unconfirmed Planned Retirement, the Generation Resource must meet the following criteria: (1) a specific retirement date is cited in the announcement, or other timing information is given that indicates the unit will be unavailable as of the start of Season *s* for Year *i*, and (2) the announcement, with follow-up inquiry by ERCOT, does not indicate that retirement timing is highly speculative.

Variable	Unit	Definition
p	None	Reserve Risk Period. The range of consecutive hours having the highest risk of operating reserve shortages for each season as determined by an ELCC study per Section 3.2.6.2. ~~Morning: For the winter season only, Hour Ending 0600 through 0900.~~ ~~Afternoon: For all seasons, Hour Ending 1500 through 1800.~~ ~~Evening: For all seasons, Hour Ending 1900 through 2200.~~
i	None	Year.
s	None	Season. ~~Spring (March through May)~~ Summer (June through September) ~~Fall (October through November)~~ Winter (December through February)

[NPRR1219: Replace the variable "s" above with the following no sooner than January 1, 2025:]

s	None	Season. Spring (March through May) Summer (June through September) Fall (October through November) Winter (December through February)

~~*d*~~	~~None~~	~~ESR design duration class. Energy Storage Resources are classified into the following five design duration classes for reporting:~~ ~~— Greater than 1 hour and less than or equal to 2 hours~~ ~~— Greater than 2 hours and less than or equal to 4 hours~~ ~~— Greater than 4 hours and less than or equal to 8 hours~~ ~~— Greater than 8 hours and less than or equal to 10 hours~~ ~~— Greater than 10 hours~~ ~~For battery ESRs, the design duration is defined as the ESR's rated energy capacity (maximum State of Charge in MWh) divided by the Real Power Rating (MW) as reported in the RIOO system.~~

Variable	Unit	Definition
sr	None	West, Far West, and Other solar regions. PVGRs are classified into regions based on the county that contains their Point of Interconnection Bus (POIB). The West region is defined as the following counties: Archer, Armstrong, Bailey, Baylor, Borden, Briscoe, Callahan, Carson, Castro, Childress, Clay, Cochran, Coke, Coleman, Collingsworth, Concho, Cottle, Crockett, Crosby, Dallam, Dawson, Deaf Smith, Dickens, Donley, Fisher, Floyd, Foard, Garza, Glasscock, Gray, Hale, Hall, Hansford, Hardeman, Hartley, Haskell, Hockley, Howard, Hutchinson, Irion, Jones, Kent, King, Knox, Lamb, Lipscomb, Lubbock, Lynn, Martin, Menard, Mitchell, Moore, Motley, Nolan, Ochiltree, Oldham, Parmer, Potter, Randall, Reagan, Roberts, Runnels, Schleicher, Scurry, Shackelford, Sherman, Sterling, Stonewall, Sutton, Swisher, Taylor, Terry, Throckmorton, Tom Green, Val Verde, Wheeler, Wichita. The Far West region is defined as the following counties: Andrews, Brewster, Crane, Culberson, Ector, El Paso, Gaines, Hudspeth, Jeff Davis, Loving, Midland, Pecos, Presidio, Reeves, Terrell, Upton, Ward, Winkler, Yoakum. The Other solar region consists of all other counties in the ERCOT Region.
wr	None	Coastal, Panhandle, and Other wind regions. WGRs are classified into regions based on the county that contains their Point of Interconnection Bus (POIB). The Coastal region is defined as the following counties: Aransas, Brazoria, Calhoun, Cameron, Kenedy, Kleberg, Matagorda, Nueces, Refugio, San Patricio, and Willacy. The Panhandle region is defined as the following counties: Armstrong, Bailey, Briscoe, Carson, Castro, Childress, Cochran, Collingsworth, Crosby, Dallam, Deaf Smith, Dickens, Donley, Floyd, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Lamb, Lipscomb, Lubbock, Moore, Motley, Ochiltree, Oldham, Parmer, Potter, Randall, Roberts, Sherman, Swisher, and Wheeler. The Other region consists of all other counties in the ERCOT Region.

16.5.4 Maintaining and Updating Resource Entity Information

(1) Each Resource Entity must timely update information the Resource Entity provided to ERCOT in the application process, and a Resource Entity must promptly respond to any reasonable request by ERCOT for updated information regarding the Resource Entity or the information provided to ERCOT by the Resource Entity, including:

(a) The Resource Entity's addresses;

(b) A list of Affiliates; and

(c) Designation of the Resource Entity's officers, directors, Authorized Representatives, and USA (all per the Resource Entity application) including the telephone and e-mail addresses for those persons.

(2) A Resource Entity that has a Switchable Generation Resource (SWGR) shall submit a report to ERCOT in writing indicating whether or not it has any contractual requirement in a non-ERCOT Control Area ~~for each season as defined in Section 3.2.6.4, Total Capacity Estimates,~~~~during the summer or winter Peak Load Seasons~~ during the summer or winter Peak Load Seasons which may cause the identified capacity to not be available to the ERCOT System for the subsequent ten years. The initial communication and subsequent updates to previously reported unavailable capacity shall be filed with ERCOT as soon as possible, but in no event later than ten Business Days after the information is obtained. The communications should reflect the Resource Entity's best estimate of the required information at the time the filing is made. ERCOT shall use the provided data for preparation of the Report on Capacity, Demand and Reserves in the ERCOT Region and other planning purposes.~~ The SWGR information reporting form is located on the ERCOT website.~~

[NPRR1219: Replace paragraph (2) above with the following no sooner than January 1, 2025:]

(2) A Resource Entity that has a Switchable Generation Resource (SWGR) shall submit a report to ERCOT in writing indicating whether or not it has any contractual requirement in a non-ERCOT Control Area for each season as defined in Section 3.2.6.4, Total Capacity Estimates, which may cause the identified capacity to not be available to the ERCOT System for the subsequent ten years. The initial communication and subsequent updates to previously reported unavailable capacity shall be filed with ERCOT as soon as possible, but in no event later than ten Business Days after the information is obtained. The communications should reflect the Resource Entity's best estimate of the required information at the time the filing is made. ERCOT shall use the provided data for preparation of the Report on Capacity, Demand and Reserves in the ERCOT Region and other planning purposes. The SWGR information reporting form is located on the ERCOT website.

Revised ERCOT Impact Analysis Report

NPRR Number	1219	NPRR Title	Methodology Revisions and New Definitions for the Report on Capacity, Demand and Reserves in the ERCOT Region (CDR)
Impact Analysis Date	July 30, 2024		
Estimated Cost/Budgetary Impact	Less than $20k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect within 3-4 months following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor 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
None.

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NPRR Number	1225	NPRR Title	Exclusion of Lubbock Load from Securitization Charges
Date of Decision	August 20, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: Not applicable		
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	26.2, Securitization Default Charges 27.3, Securitization Uplift Charge 27.5.4, Determination of Securitization Uplift Charge Credit Exposure for a Counter-Party		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) updates the Protocols to align with the PUCT's decisions in PUCT Docket No. 56119, Petition of Electric Reliability Council of Texas, Inc. for Expedited Declaratory Order Regarding Public Utility Regulatory Act Chapter 39, Subchapter N; and Docket No. 56122, Petition of Electric Reliability Council of Texas, Inc. for Expedited Declaratory Order Regarding Public Utility Regulatory Act Chapter 39, Subchapter M. To comply with the PUCT's declaratory orders, ERCOT changed its Settlement systems to implement the PUCT-ordered exclusions to be effective on or before March 4, 2024, the day on which the transfer of Lubbock Power and Light (LP&L) retail Customers to Retail Electric Providers (REPs) began. This NPRR reflects in the Protocols those exclusions. The changes include: • Incorporating the Load activity for current and future end-use Customers in LP&L's service area to the billing determinant Opt-Out LSE Real-Time Adjusted Metered Load (OPTOUTLSERTAML) in Section 27.3; and		

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	• Updating the calculation of Securitization Default Charge Real-Time Adjusted Metered Load (SDCRTAML) in Section 26.2. A new billing determinant, RTAMLEXSECM, was created to exclude the Load activity for end-use Customers in LP&L's service area, replacing the existing Real-Time Adjusted Metered Load (RTAML) billing determinant in this calculation.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ Administrative ☒ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	In Docket No. 56119, the PUCT granted ERCOT's petition and issued a Declaratory Order concluding in part that end-use Customers in the service area of the City of Lubbock, acting by and through LP&L remain exempt from the assessment of Securitization Uplift Charges upon the commencement of LP&L's transition to retail competition. The PUCT interpreted PURA § 39.151(j-1) and the PUCT's Debt Obligation Order in PUCT Docket No. 52322, Application of the Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter N, of the Public Utility Regulatory Act, ordering, inter alia, that ERCOT must not assess Securitization Uplift Charges to Qualified Scheduling Entities (QSEs) representing Load Serving Entities (LSEs) for the portion of Load they serve that is associated with those current and future Electric Service Identifiers (ESI IDs) registered to LP&L as a Transmission and/or Distribution Service Provider (TDSP) in LP&L's service area. Similarly, in Docket No. 56122, the PUCT granted ERCOT's petition and issued a Declaratory Order concluding in part that end-use Customers in the service area of LP&L remain exempt from the assessment of Securitization Default Charges upon the

	commencement of LP&L's transition to retail competition. Interpreting PURA § 39.151(j-1) and the PUCT's Debt Obligation Order in PUCT Docket No. 52321, Application of the Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M, of the Public Utility Regulatory Act, the PUC ordered, inter alia, that ERCOT continue to exclude LP&L and implement a process to exclude the current and future ESI IDs registered to LP&L as a TDSP from the calculation of Securitization Default Charges. The Commission concluded that ERCOT should exclude only market activity used to calculate Securitization Default Charges based on the volume of Load activity for end-use Customers in LP&L's service area; ERCOT cannot identify, segregate, and remove other market activities included in the Securitization Default Charge assessment methodology, such as energy trades, Day-Ahead activity, and Congestion Revenue Rights (CRRs) purchased and owned. This NPRR reflects the PUCT's decisions in its declaratory orders issued in PUCT Dockets Nos. 56119 and 56122, consistent with the legislative intent (codified in PURA § 39.151(j-1)) that end-use Customers in the service area of LP&L should not be subject to Securitization Default Charges and Securitization Uplift Charges.
PRS Decision	On 5/9/24, PRS voted unanimously to recommend approval of NPRR1225 as submitted. All Market Segments participated in the vote. On 6/13/24, PRS voted unanimously to endorse and forward to TAC the 5/9/24 PRS Report and 4/11/24 Impact Analysis for NPRR1225. All Market Segments participated in the vote.
Summary of PRS Discussion	On 5/9/24, ERCOT Staff provided an overview of NPRR1225. On 6/13/24, there was no discussion.
TAC Decision	On 6/24/24, TAC voted unanimously to recommend approval of NPRR1225 as recommended by PRS in the 6/13/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/24/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed

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	[X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 8/20/24, the ERCOT Board voted unanimously to recommend approval of NPRR1225 as recommended by TAC in the 6/24/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and CFSG have reviewed NPRR1225 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1225.
ERCOT Opinion	ERCOT supports approval of NPRR1225.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1225 and believes the market impact for NPRR1225 properly aligns Protocol language with as-built Settlement system calculations to exclude LP&L Load from Securitization uplift and default charges, as directed by the PUCT.

Sponsor	
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Company	ERCOT
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Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
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Comments Received

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Comment Author	Comment Summary
None	

Market Rules Notes

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

- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
  - Section 26.2
- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
  - Section 26.2

Proposed Protocol Language Revision

26.2 Securitization Default Charges

Commented [CP1]: Please note NPRRs 1188 and 1246 also propose revisions to this section.

(1) ERCOT shall issue Invoices to Qualified Scheduling Entities (QSEs) and Congestion Revenue Right (CRR) Account Holders to collect the monthly amount determined by ERCOT to be necessary to repay the Securitization Default Balance. ERCOT may assess Securitization Default Charges over a period of up to 30 years.

(2) Each Counter-Party's share of the Securitization Default Charge for a month is calculated using the best available Settlement data for the most recent month for which ERCOT has posted Final Settlement data for all Operating Days in the month (referred to below as "the reference month"), as follows:

$$\mathbf{SDCRSCP}_{cp} = \mathbf{TSDCMA} * \mathbf{SDCMMARS}_{cp}$$

Where:

$$\text{SDCMMARS}_{cp} = \text{SDCMMA}_{cp} / \text{SDCMMATOT}$$

$$\text{SDCMMA}_{cp} = \text{Max}\ \{ \textstyle\sum_{mp} (\text{SDCRTMG}_{mp} + \text{SDCRTDCIMP}_{mp}),$$

$$\textstyle\sum_{mp} (\text{SDCRTAML}_{mp} + \text{SDCWSLTOT}_{mp}),$$

$$\textstyle\sum_{mp} \text{SDCRTQQES}_{mp},$$

$$\textstyle\sum_{mp} \text{SDCRTQQEP}_{mp},$$

$$\textstyle\sum_{mp} \text{SDCDAES}_{mp},$$

$$\textstyle\sum_{mp} \text{SDCDAEP}_{mp},$$

$\sum_{mp}$ (SDCRTOBL $_{mp}$ + SDCRTOBLLO $_{mp}$),

$\sum_{mp}$ (SDCDAOPT $_{mp}$ + SDCDAOBL $_{mp}$ + SDCOPTS $_{mp}$ + SDCOBLS $_{mp}$),

$\sum_{mp}$ (SDCOPTP $_{mp}$ + SDCOBLP $_{mp}$)}

SDCMMATOT = $\sum_{cp}$ (SDCMMA $_{cp}$)

Where:

SDCRTMG $_{mp}$ = $\sum_{r,\,p,\,i}$ (RTMG $_{mp,\,r,\,p,\,i}$), excluding RTMG for Reliability Must-Run (RMR) Resources and RTMG in Reliability Unit Commitment (RUC)-Committed Intervals for RUC-committed Resources

SDCRTDCIMP $_{mp}$ = $\sum_{p,\,i}$ (RTDCIMP $_{mp,\,p,\,i}$) / 4

SDCRTAML $_{mp}$ = max(0,$\sum_{p,\,i}$ (RTAMLEXSECM $_{mp,\,p,\,i}$))

SDCRTQQES $_{mp}$ = $\sum_{p,\,i}$ (RTQQES $_{mp,\,p,\,i}$) / 4

SDCRTQQEP $_{mp}$ = $\sum_{p,\,i}$ (RTQQEP $_{mp,\,p,\,i}$) / 4

SDCDAES $_{mp}$ = $\sum_{p,\,h}$ (DAES $_{mp,\,p,\,h}$)

SDCDAEP $_{mp}$ = $\sum_{p,\,h}$ (DAEP $_{mp,\,p,\,h}$)

SDCRTOBL $_{mp}$ = $\sum_{(j,\,k),\,h}$ (RTOBL $_{mp,\,(j,\,k),\,h}$)

SDCRTOBLLO $_{mp}$ = $\sum_{(j,\,k),\,h}$ (RTOBLLO $_{mp,\,(j,\,k),\,h}$)

SDCDAOPT $_{mp}$ = $\sum_{(j,\,k),\,h}$ (OPT $_{mp,\,(j,\,k),\,h}$)

SDCDAOBL $_{mp}$ = $\sum_{(j,\,k),\,h}$ (DAOBL $_{mp,\,(j,\,k),\,h}$)

SDCOPTS $_{mp}$ = $\sum_{(j,\,k),\,h}$ (OPTS $_{mp,\,(j,\,k),\,h}$)

SDCOBLS $_{mp}$ = $\sum_{(j,\,k),\,h}$ (OBLS $_{mp,\,(j,\,k),\,h}$)

SDCOPTP $_{mp}$ = $\sum_{(j,\,k),\,h}$ (OPTP $_{mp,\,j,\,h}$)

SDCOBLP $_{mp}$ = $\sum_{(j,\,k),\,h}$ (OBLP $_{mp,\,(j,\,k),\,h}$)

SDCWSLTOT $_{mp}$ = (-1) * $\sum_{r,\,b}$ (MEBL $_{mp,\,r,\,b}$)

The above variables are defined as follows:

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Variable	Unit	Definition
SDCRSCP $_{cp}$	\$	*Securitization Default Charge Ratio Share per Counter-Party*—The Counter-Party's pro rata portion of the total Securitization Charges for a month.
TSDCMA	\$	*Total Securitization Default Charge Monthly Amount*—The amount ERCOT determines must be collected for the month in order to timely repay the Securitization Default Balance.
SDCMMARS $_{cp}$	None	*Securitization Default Charge Maximum MWh Activity Ratio Share*—The Counter-Party's pro rata share of Maximum MWh Activity.
SDCMMA $_{cp}$	MWh	*Securitization Default Charge Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction for the reference month.
SDCMMATOT	MWh	*Securitization Default Charge Maximum MWh Activity Total*—The sum of all Counter-Party's Maximum MWh Activity.
RTMG $_{mp, p, r, i}$	MWh	*Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTMG $_{mp}$	MWh	*Securitization Default Charge Real-Time Metered Generation per Market Participant*—The monthly sum in the reference month of Real-Time energy produced by Generation Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTDCIMP $_{mp, p, i}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTDCIMP $_{mp}$	MW	*Securitization Default Charge Real-Time DC Import per Market Participant*—The monthly sum in the reference month of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party.
RTAMLEXSECM $_{mp, p, i}$	MWh	*Real-Time Adjusted Metered Load Excluding Load Exempt from Sub M per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML), excluding Load that is exempt from Securitization Default Charges pursuant to the Declaratory Order entered by the Public Utility Commission of Texas (PUCT) in PUCT Docket No. 56122, *Petition of Electric Reliability Council of Texas, Inc. for Expedited Declaratory Order Regarding Public Utility Regulatory Act Chapter 39, Subchapter M*, at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTAML $_{mp}$	MWh	*Securitization Default Charge Real-Time Adjusted Metered Load per Market Participant*—The monthly sum in the reference month of the AML, excluding Load exempt from Securitization Default Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56122, represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQES $_{mp, p, i}$	MW	*QSE-to-QSE Energy Sale per Market Participant per Settlement Point*—The amount of MW sold by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.

Variable	Unit	Definition
SDCRTQQES $_{mp}$	MWh	*Securitization Default Charge QSE-to-QSE Energy Sale per Market Participant*—The monthly sum in the reference month of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQEP $_{mp, p, i}$	MW	*QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTQQEP $_{mp}$	MWh	*Securitization Default Charge QSE-to-QSE Energy Purchase per Market Participant*—The monthly sum in the reference month of MW bought by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAES $_{mp, p, h}$	MW	*Day-Ahead Energy Sale per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offers at Settlement Point *p*, for the hour *h*, where the Market Participant is a QSE.
SDCDAES $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Energy Sale per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAEP $_{mp, p, h}$	MW	*Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared DAM Energy Bids at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE.
SDCDAEP $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Energy Purchase per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*'s cleared DAM Energy Bids, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBL $_{mp, (j, k), h}$	MW	*Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE.
SDCRTOBL $_{mp}$	MWh	*Securitization Default Charge Real-Time Obligation per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBLLO $_{q, (j, k)}$	MW	*Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of the QSE's PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.
SDCRTOBLLO $_{q, (j, k)}$	MW	*Securitization Default Charge Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The monthly total in the reference month of Market Participant *mp*'s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party.
OPT $_{mp, (j, k), h}$	MW	*Day-Ahead Option per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.

Variable	Unit	Definition
SDCDAOPT $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Option per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
DAOBL $_{mp,\ (j,\ k),\ h}$	MW	*Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
SDCDAOBL $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Obligation per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTS $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOPTS $_{mp}$	MWh	*Securitization Default Charge PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLS $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOBLS $_{mp}$	MWh	*Securitization Default Charge PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTP $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOPTP $_{mp}$	MWh	*Securitization Default Charge PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLP $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOBLP $_{mp}$	MWh	*Securitization Default Charge PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.

Variable	Unit	Definition
SDCWSLTOT $_{mp}$	MWh	*Securitization Default Charge Metered Energy for Wholesale Storage Load at bus per Market Participant*—The monthly sum in the reference month of Market Participant *mp*'s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL.
MEBL $_{mp,\ r,\ b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*.
cp	none	A registered Counter-Party.
mp	none	A Market Participant that is a QSE or CRR Account Holder with activity in the reference month, except for a Market Participant exempt from Securitization Default Charges pursuant to the Final Order entered by the Public Utility Commission of Texas (PUCT) in PUCT Docket No. 52321, Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M. Defaulted Market Participants with market activity in the reference month are included in the calculation.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.
p	none	A Settlement Point.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
r	none	A Resource.

(3) The Securitization Default Charge amount will be allocated to the QSE or CRR Account Holder assigned to a registered Counter-Party based on the pro-rata share of MWhs that the QSE or CRR Account Holder contributed to its Counter-Party's maximum MWh activity ratio share.

(4) As needed, but no less than annually, ERCOT will conduct an evaluation to determine if the Total Securitization Default Charge Monthly Amount (TSDCMA), which is the amount collected each month to repay the Securitization Default Balance, should be modified. In conducting this evaluation, ERCOT will calculate the amount that must be collected each month to service the then-remaining Securitization Default Balance debt in even monthly amounts over the remaining tenor of the debt.

(5) If ERCOT modifies the TSDCMA pursuant to paragraph (4) above, ERCOT will issue a Market Notice notifying Market Participants of the change no later than 15 days before the beginning of the month in which the new TSDCMA will be used to calculate the Securitization Default Charges.

27.3 Securitization Uplift Charge

(1) ERCOT shall allocate to Qualified Scheduling Entities (QSEs) representing obligated Load Serving Entities (LSEs), the Securitization Uplift Charge that is to be collected for the Operating Day. The resulting charge to each QSE for the Operating Day is calculated as follows:

$$\mathbf{LASUCAMT}_{q,\,d} = \mathbf{SUCDA}_{d} * \mathbf{DQSELSELRS}_{q,\,d}$$

Where:

$$\text{DQSELSELRS}_{q,\,d} = \text{DQSELSERTAML}_{q,\,d} / \text{DERCOTQSELSERTAML}_{d}$$

$$\text{DQSELSERTAML}_{q,\,d} = \max(0,\ \sum_{i,l}(\text{LSERTAML}_{l,\,q,\,i}))$$

$$\text{DERCOTQSELSERTAML}_{d} = \sum_{q}(\text{DQSELSERTAML}_{q,\,d})$$

$$\text{LSERTAML}_{l,\,q,\,i} = \text{PRELIMLSERTAML}_{l,\,q,\,i} - \text{OPTOUTLSERTAML}_{l,\,q,\,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
LASUCAMT $_{q,\,d}$	$	*Load-Allocated Securitization Uplift Charge Amount per QSE* — The charge allocated to QSE *q*, for the QSE's share of the total amount of Securitization Uplift Charges assessed for Operating Day *d*.
SUCDA $_{d}$	$	*Securitization Uplift Charge Daily Amount* — The total amount of Securitization Uplift Charges assessed for Operating Day *d*.
DQSELSELRS $_{q,\,d}$	none	*Daily QSE Non-Opted-Out LSE Load Ratio Share* — The ratio of Daily QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load (DQSELSERTAML) to Daily ERCOT QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load (DERCOTQSELSERTAML), for a QSE *q*, for the Operating Day *d*.
PRELIMLSERTAML $_{l,\,q,\,i}$	MWh	*Preliminary Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML), including the RTAML of Securitization Uplift Charge Opt-Out Entities that are Customers of Retail Electric Providers (REPs), but excluding the RTAML of Securitization Uplift Charge Opt-Out Entities that are LSEs and excluding Direct Current Tie (DC Tie) exports, for LSE *l* represented by QSE *q*, for the 15-minute Settlement Interval *i*.
LSERTAML $_{l,\,q,\,i}$	MWh	*Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML), excluding the RTAML for Securitization Uplift Charge Opt-Out Entities, Load that is exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the Public Utility Commission of Texas (PUCT) in PUCT Docket No. 56119, *Petition of Electric Reliability Council of Texas, Inc. for Expedited Declaratory Order Regarding Public Utility Regulatory Act Chapter 39, Subchapter N*, and ~~excluding~~ DC Tie exports, for LSE *l* represented by QSE *q*, for the 15-minute Settlement Interval *i*.
OPTOUTLSERTAML $_{l,\,q,\,i}$	MWh	*Opt-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML) of Securitization Uplift Charge Opt-Out Entities that are transmission-voltage Customers and Load exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56119 for LSE *l* represented by QSE *q*, for the 15-minute Settlement Interval *i*.

DQSELSERTAML $_{q,\ d}$	MWh	*Daily QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML), excluding the RTAML for Securitization Uplift Charge Opt-Out Entities, Load exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56119, and ~~excluding~~ DC Tie exports, for a QSE *q*, for the Operating Day *d*.
DERCOTQSELSERTAML $_{d}$	MWh	*Daily ERCOT QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The ERCOT total Real-Time Adjusted Metered Load (RTAML), excluding the RTAML for Securitization Uplift Charge Opt-Out Entities, Load exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56119, and DC Tie exports, for the Operating Day *d*.
q	none	A QSE
l	none	An LSE
d	none	An Operating Day
i	none	A 15-minute Settlement Interval

(2) As needed, but no less often than quarterly, ERCOT will, to ensure the Securitization Uplift Charge is repaid in substantially equal payments over its term, conduct an evaluation to:

(a) Calculate under-collections or over-collections from the preceding evaluation period;

(b) Estimate any anticipated under-collections or over-collections for the current or upcoming evaluation period; and

(c) Calculate the periodic billing requirement for the upcoming evaluation period, taking into account the total amount of prior and anticipated over-collection and under-collection amounts, and calculate the Securitization Uplift Charge Daily Amount for future periodic billing requirements.

(3) If it is determined in the re-estimation process that the Securitization Uplift Charge Daily Amount needs to be revised, ERCOT will issue a Market Notice notifying Market Participants of the change no later than 15 calendar days before the Operating Day in which the new Securitization Uplift Charge Daily Amount will become effective.

(4) An LSE that is not a Securitization Uplift Charge Opt-Out Entity is responsible for remitting payment to its QSE for the LSE's share of the Securitization Uplift Charge, based on the LSE's Non-Opted-Out LSE Adjusted Metered Load (AML). An LSE may not pass through the Securitization Uplift Charge to any transmission-voltage Customer that is a Securitization Uplift Charge Opt-Out Entity. ERCOT shall post to the ERCOT website a list that consists solely of every Electric Service Identifier (ESI ID) associated with a transmission-voltage Customer that is a Securitization Uplift Charge Opt-Out Entity. This list of ESI IDs will not include the identity of the Customer or its Retail Electric Provider (REP).

27.5.4 *Determination of Securitization Uplift Charge Credit Exposure for a Counter-Party*

(1) For each Counter-Party, ERCOT shall calculate the Securitization Uplift Charge Credit Exposure for Securitization Uplift Charge Initial Invoices as follows:

$\text{LASUCCE}_{cp} = \sum_{fmu=1}^{nfmu}$(Max (CPMQSELSELRS $_{cp,\ om,\ las}$, CPIEMLSELRS $_{cp}$ up to 40 days after the operating month in which a non-opted-out Counter-Party Load Serving Entity (LSE) commences having Real-Time Adjusted Metered Load (AML)) * MTSUCDA $_{fmu}$)

$$\text{CPMQSELSELRS}_{cp,\ om,\ las} = \sum_{q}(\text{MQSELSELRS}_{q,\ om})$$

$$\text{CPIEMLSELRS}_{cp} = \text{CPIEMLSE}_{cp} \,/\, (\text{MERCOTQSELSERTAML}_{om} + \text{CPIEMLSE}_{cp})$$

$$\text{MQSELSELRS}_{q,\ om} = \text{MQSELSERTAML}_{q,\ om} \,/\, \text{MERCOTQSELSERTAML}_{om}$$

$$\text{MQSELSERTAML}_{q,\ om} = \sum_{d}(\text{DQSELSERTAML}_{q,\ d})$$

$$\text{MERCOTQSELSERTAML}_{om} = \sum_{q,d}(\text{DQSELSERTAML}_{q,\ d})$$

The above variables are defined as follows:

Variable	Unit	Description
LASUCCE_{cp}	$	*Load-Allocated Securitization Uplift Charge Credit Exposure* – Estimated forward exposure representing unbilled Securitization Uplift Charge Initial Invoices for Counter-Party *cp* for *nfmu* months.
$\text{CPMQSELSELRS}_{cp,\ om,\ las}$	None	*Counter-Party Monthly QSE Non-Opted-Out LSE Load Ratio Share* — MQSELSELRS for all the QSEs represented by the Counter-Party *cp* representing the daily ratios of AML to the total AML, excluding the AML for Securitization Uplift Charge Opt-Out Entities, Load exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56119, and Direct Current Tie (DC Tie) exports, for a QSE, for all the Operating Days *d* in the operating month *om* for the Settlement Type *las*.
CPIEMLSE_{cp}	MWh	*Counter-Party Initial Estimated Monthly Non-Opted-Out LSE Load* — The average estimated ~~l~~Load for a full month provided by a non-opted-out Counter-Party *cp* that does not yet have AML.
CPIEMLSELRS_{cp}	None	*Counter-Party Initial Estimated Monthly Non-Opted-Out LSE Load Ratio Share* — The Load Ratio Share (LRS) for a Counter-Party *cp* that does not yet have AML, computed using CPIEMLSE.
MTSUCDA	$	*Monthly Total of Securitization Uplift Charge Daily Amounts* – The monthly sum of the amounts to be uplifted for all the Operating Days *od* in operating month *om*.
$\text{DQSELSERTAML}_{q,\ d}$	MWH	*Daily QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The Real-Time Adjusted Metered Load (RTAML) excluding the RTAML for Securitization Uplift Charge Opt-Out Entities, Load exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56119, and DC Tie exports, for a QSE *q*, for the Operating Day *d*.

Variable	Unit	Description
$MQSELSELRS_{q, om}$	none	*Monthly QSE Non-Opted-Out LSE Load Ratio Share* — The ratio of AML to the total AML, excluding the AML for Securitization Uplift Charge Opt-Out Entities<u>, Load exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56119,</u> and DC Tie exports, for a QSE *q*, for all the Operating Days *d* in the operating month *om*.
$MQSELSERTAML_{q, om}$	MWH	*Monthly QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The RTAML excluding the RTAML for Securitization Uplift Charge Opt-Out Entities<u>, Load exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56119,</u> and DC Tie exports, for a QSE *q*, for all the Operating Days *d* in the operating month *om*.
$MERCOTQSELSERTAML_{om}$	MWH	*Monthly ERCOT QSE Non-Opted-Out LSE Real-Time Adjusted Metered Load* — The ERCOT total RTAML excluding the RTAML for Securitization Uplift Charge Opt-Out Entities<u>, Load exempt from Securitization Uplift Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56119, </u> and DC Tie exports, for all the Operating Days *d* in the operating month *om*.
cp	none	A registered Counter-Party.
om	none	*Operating Month* – The most recent month for which all the daily ratios of AML to the total AML, excluding the AML for Securitization Uplift Charge Opt-Out Entities and DC Tie exports, for a QSE are available for all days of the month.
fmu	none	*Forward Month* – A month from Securitization Uplift Charge forward months.
nfmu	none	*Number of forward months* – Total number of forward months Monthly Securitization Uplift Charge is extrapolated.
d	none	An Operating Day.

The above parameters are defined as follows:

Parameter	Unit	Current Value
nfmu	Months	2
las	Settlement Type	Load-Allocated Initial Settlements

ERCOT Impact Analysis Report

NPRR Number	**<u>1225</u>**	**NPRR Title**	**Exclusion of Lubbock Load from Securitization Charges**
Impact Analysis Date	April 11, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) 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	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
None.

Board Report

NPRR Number	1230	NPRR Title	Methodology for Setting Transmission Shadow Price Caps for an IROL in SCED
Date of Decision	August 20, 2024		
Action	Recommended Approval		
Timeline	Urgent – to expedite improvements that will enable ERCOT to manage power flows within Interconnection Reliability Operating Limits (IROLs) using existing operational and market tools rather than relying on manual intervention by ERCOT operators. ERCOT must ensure power flows remain within IROLs to prevent system instability, uncontrolled separation, and cascading. Expediting these enhancements could reduce the likelihood and/or magnitude of any Load-shedding that may be required to ensure the IROLs are not exceeded.		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	Section 22 Attachment P, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) establishes a Shadow Price cap for congestion impacting an IROL.		
Reason for Revision	[X] Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience [ ] Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers [ ] Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice		

	by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	ERCOT is required to ensure that power flows do not exceed any IROL on the ERCOT System in order to prevent system instability, uncontrolled separation, and cascading. Therefore, the Shadow Price cap of an IROL must be set at a value such that Security-Constrained Economic Dispatch (SCED) will continue to manage the IROL constraint even during periods of system-wide scarcity. This NPRR establishes the methodology for calculating the Shadow Price cap for IROLs. This NPRR will enable ERCOT to manage power flows within IROLs using existing operational and market tools instead of relying on manual intervention by ERCOT operators. The manual intervention methods currently being used introduce operational risk during periods of stressed system conditions.
PRS Decision	On 5/9/24, PRS voted to grant NPRR1230 Urgent status. There were two opposing votes from the Independent Generator (2) (Constellation, Calpine) Market Segment and six abstentions from the Independent Generator (Jupiter Power), Independent Power Marketer (IPM) (Tenaska), Investor Owned Utility (IOU) (Linebacker Power), and Municipal (3) (CPS Energy, GEUS, Austin Energy) Market Segments. PRS then voted to recommend approval of NPRR1230 as revised by PRS and to forward to TAC NPRR1230 and the 5/7/24 Impact Analysis. There were twelve abstentions from the Independent Generator (6) (Constellation, Jupiter Power, Calpine, NextEra Energy, ENGIE, EDF Renewables), IPM (3) (Tenaska, SENA, NG Renewables), IOU (Linebacker Power), and Municipal (2) (CPS Energy, GEUS) Market Segments. All Market Segments participated in both votes.
Summary of PRS Discussion	On 5/9/24, ERCOT Staff provided an overview of NPRR1230 and provided a presentation on the background of the issue and the need for urgency. Participants proposed desktop edits to provide at least 30 days' notice ahead of changing IROL Shadow Price caps in the future.

Board Report

TAC Decision	On 5/22/24, TAC voted to table NPRR1230. There was one abstention from the Independent Generator (Luminant) Market Segment. All Market Segments participated in the vote. On 7/31/24, TAC voted to recommend approval of NPRR1230 as recommended by PRS in the 5/9/24 PRS Report as amended by the 5/29/24 ERCOT comments as revised by TAC. There were two opposing votes from the Cooperative (LCRA) and Municipal (Austin Energy) Market Segment and four abstentions from the Cooperative (3) (GSEC, PEC, STEC) and Independent Retail Electric Provider (IREP) (APG&E) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, TAC reviewed the items below, but requested additional time to review NPRR1230 and the appropriate amount of notice ahead of any Shadow Price cap changes. On 7/31/24, ERCOT Staff provided requested analysis of 2023 data based on NPRR1230 mechanics. TAC reviewed the 5/29/24 ERCOT comments and proposed desktop edits to update the proposed effective date of grey-boxed language. Opponents urged continued use of manual intervention steps as a less costly solution rather than the systematic solution proposed in NPRR1230.
Explanation of Opposing TAC Votes	**Cooperative/LCRA** – ERCOT filed NPRR1230 in direct response to summer 2023 operational events on the South Texas Export and Import Generic Transmission Constraints ("STX GTC"). At TAC on 7/31/24, ERCOT presented a 2023 backcast analysis that indicated that the market cost for Load (i.e., Load quantity times Load price) would've increased between $0.5B and $1.6B over 20 operating days in the study. LCRA believes that this cost increase is not justified. ERCOT already has a method in place to relieve these constraints (i.e., issuance of High Dispatch Limit (HDL) overrides) that is significantly cheaper than the mechanics that NPRR1230 imposes. For example, the HDL overrides issued on 9/6/23 only resulted in $185K of uplift cost to Load. To put these cost numbers into context, if a 9/6/23 event happened every single day it would take between 7.5 and 24 years for the HDL override uplift cost to equal the 2023 NPRR1230 cost as indicated by ERCOT's analysis. Additionally, ERCOT has outlined a STX GTC exit strategy that indicates that transmission solutions resolving this issue will be in service starting in 2027. LCRA does not support this change as it will serve to increase risk and hedging cost into the future which does not serve to keep costs low for our customers. As detailed above, there is a cheaper solution already in place and a permanent solution is on the horizon.

Board Report

	Municipal/Austin Energy – Austin Energy voted against this NPRR due to its increased cost to specific Load Zones. We appreciate the extra time that ERCOT and stakeholders provided us on this NPRR so that we can hedge against the cost in the future.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 8/20/24, the ERCOT Board voted unanimously to recommend approval of NPRR1230 as recommended by TAC in the 7/31/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1230 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM supports approval of NPRR1230.
ERCOT Opinion	ERCOT supports approval of NPRR1230.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1230 and believes the market impact for NPRR1230 properly leverages existing market tools to provide additional ERCOT operator flexibility when managing IROLs.

Sponsor	
Name	Freddy Garcia
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Phone Number	512-248-4245
Cell Number	
Market Segment	Not applicable

Board Report

Market Rules Staff Contact	
Name	Cory Phillips
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Comments Received	
Comment Author	**Comment Summary**
ERCOT 052024	Proposed revisions to clarify that an increase in the Shadow Price cap for IROLs would not apply to all IROLs
ERCOT 052924	Proposed additional edits to the 5/20/24 ERCOT comments to address stakeholder feedback
ERCOT 081224	Provided additional backcast analysis of the South Texas Export limit

Market Rules Notes

Please note that the following NPRR(s) also propose revisions to Section 22, Attachment P:

- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era

Proposed Protocol Language Revision

1. PURPOSE

Commented [CP1]: Please note NPRR1246 also proposes revisions to this section.

Section 6.5.7.1.11, Transmission Network and Power Balance Constraint Management, requires the Public Utility Commission of Texas (PUCT) to approve ERCOT's methodology for establishing caps on the Shadow Prices for transmission constraints and the Power Balance constraint. Additionally, PUCT 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 (RTM) in the cases of constraint violations.

This Attachment describes:

- the PUCT-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 PUCT-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.

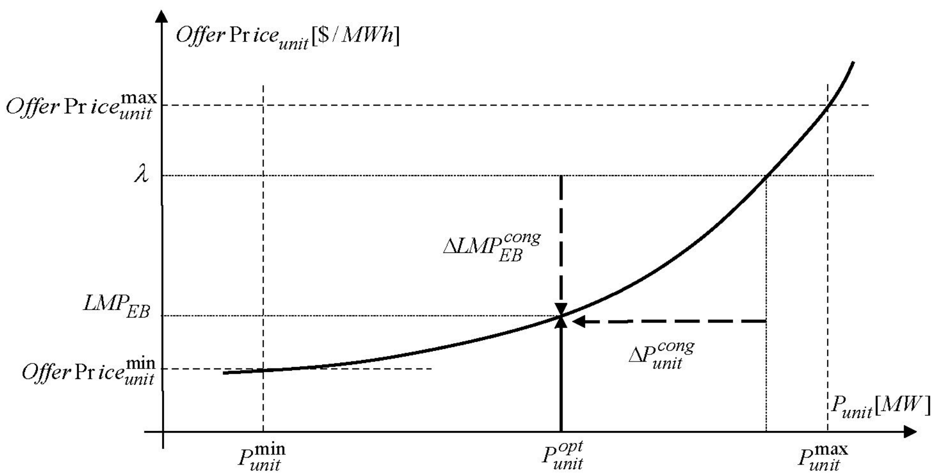
The optimal dispatch from both system (minimal congestion costs) and unit (maximal unit profit) prospective is determined by condition:

$$Offer\,Pr\,i\,ce_{unit}(P_{unit}^{opt}) = LMP_{EB}.$$

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 ΔLMP_{max}^{cong} directly limits the transmission congestion costs:

$$C_{cos\,t}^{cong} = \sum_{unit}^{\Sigma} \Delta LMP_{max}^{cong_{unit}^{opt}}.$$

The efficiency of generating unit contribution can be determined by maximal value of LMP congestion component ΔLMP_{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:

$$SP_{max}^{\ max\ \ cong_{threshold}^{efficiency}}.$$

The maximal unit power output adjustment ΔP_{max}^{cong} will be determined by condition:

$$Offer\ Pr\,i\,ce_{unit}(P_{unit} - \Delta P_{max}^{cong_{EB}{}_{threshold}^{efficency}\ max}$$

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 Energy Management System (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 ΔLMP_{max}^{cong} (default \$y/MWh)

(c) Calculate maximal Shadow Price for transmission constraints:

$$cong_{threshold}^{efficiency}$$
$$SP_{max}^{max}$$

(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 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 (GTC) Shadow Price Caps in SCED</u>

- Base Case/Voltage Violation: \$5,251/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]

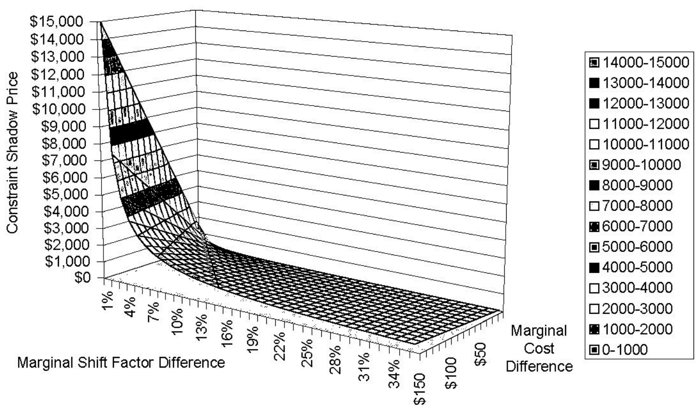


Figure 1

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 attachent, 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.

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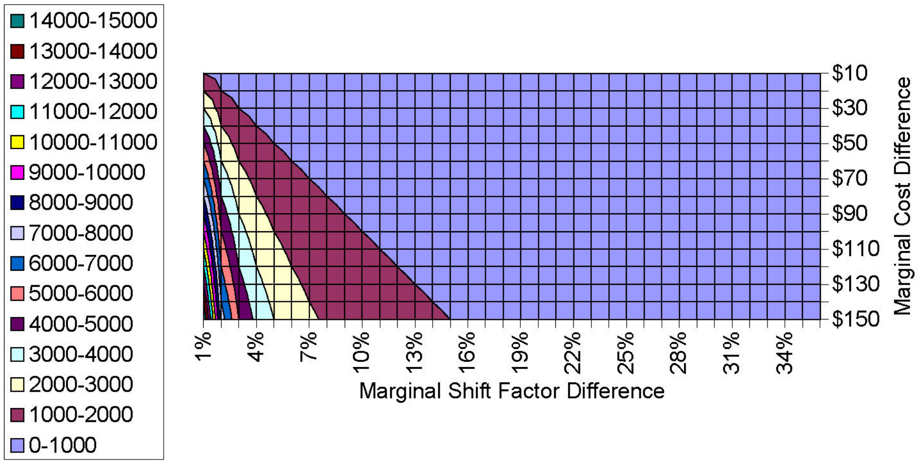

Figure 2

Figures 1 and 2 show that:

- For a constraint shadow price cap of $5,251/MW
  - Marginal units with an *offer price difference* of $52.51/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 2.9%.
- 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.

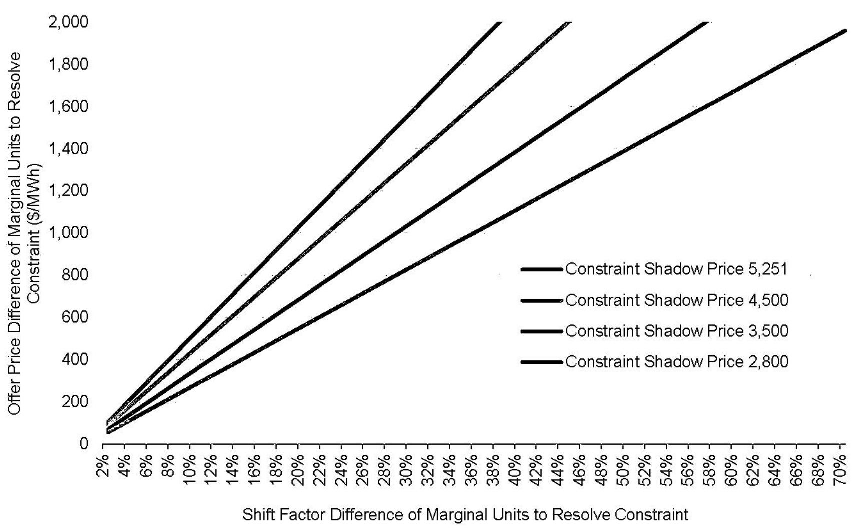

Figure 3

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 $105.02/MWh for constraint shadow price cap values of $2,800, $3,500, $4,500 and $5,251/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 $3,150.60/MWh for constraint shadow price cap values of $2,800, $3,500, $4,500 and $5,251/MW, respectively.

In some circumstances these constraint shadow price cap values may preclude the deployment of an offer at the System-Wide Offer Cap (SWCAP). However, it is not possible in the nodal design to establish constraint shadow price caps at a level that will always accept an offer at SWCAP and still produce pricing outcomes that remain within reasonable bounds of subsection (g)(6) of P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region. For example, taking the case above where the shift factor difference of the marginal units is just 2%, a constraint shadow price cap of $250,000/MW would be required to deploy $5,000/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 a $5,000/MWh SWCAP if the constraint was irresolvable. For example, a node with a shift factor of -50% would have an LMP with a congestion component of $125,000/MWh from just this one constraint, and even higher if multiple constraints are binding. In contrast, with a $5,251/MW shadow price cap, the congestion component of the LMP of the node with a shift factor of -50% would be $2,625.50/MW for just this one constraint.

The LMP at an individual node, hub or load zone can exceed the SWCAP 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 SWCAP than hubs or load zones, but it is possible that hub or load zone prices could exceed the SWCAP. 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 SWCAPs 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 Section 6.5.7.1.10, Network Security Analysis Processor and Security Violation Alarm.

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 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 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 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 (MOC) 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 MOC 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 (RAPs) or Temporary Outage Action Plans (TOAPs) 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 Independent Market Monitor (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 Settlement Point Price. This Settlement Point Price 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 Settlement Point Price – 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 (FIP) as defined in 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.

3.7 Methodology for Setting Transmission Shadow Price Caps for an IROL in SCED

Upon implementation of an IROL, the shadow price cap of an IROL shall be set by ERCOT ~~as the higher of~~to A, below. If ERCOT, in its sole discretion, determines that A, below, is insufficient for SCED to manage an IROL, ERCOT shall use B, below, to determine the shadow price cap~~or B as follows~~:

A. The value of the Generic Transmission Shadow Price Cap for Base Case constraints, as set in subsection 3.5, Generic Values for the Transmission Network System-Wide Shadow Price Caps in SCED, above; or

B. The maximum price value on the Power Balance Penalty Curve minus the mitigated offer floor for Resource H, as determined below, divided by Resource H's Shift Factor impact to the constraint.

ERCOT shall include the shadow price cap for each IROL in the associated GTC Methodology posted pursuant to Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

To determine Resource H, ERCOT shall identify all Generation Resources and Energy Storage Resource (ESRs) with positive Shift Factors not lower than 10% relative to the IROL and calculate the difference between the Seasonal net max sustainable rating ("seasonal HSL") and the Seasonal net min sustainable rating ("seasonal LSL") for each Resource in effect at the time of the calculation. Starting with the Generation Resource or ESR with the highest positive Shift Factor, ERCOT will sum the differences between seasonal HSL and seasonal LSL until the sum is greater than or equal to the MW value that, if divided by 0.1Hz, would equal the ERCOT System frequency bias ("bias MW value"). Resource H shall be the Generation Resource or ESR that results in this sum being greater than or equal to the bias MW value. If the sum of differences between the current seasonal HSL and seasonal LSL is not greater than or equal to the bias MW value, then Resource H will be the Generation Resource or ESR with the lowest positive shift factor not lower than 10%.

The shadow price cap and the Resource identified as Resource H for all IROLs may be updated at any time based on ERCOT's review and shall be reviewed by ERCOT at least annually. Any updates to IROL shadow price caps will be communicated through a Market Notice prior to becoming effective.

[NPRR1230: Replace the paragraph above with the following on~~effective~~ ~~December 1~~October~~August~~ 2, 2024:]

The shadow price cap and the Resource identified as Resource H for all applicable IROLs may be updated at any time based on ERCOT's review and shall be reviewed by ERCOT at least annually. Any updates to IROL shadow price caps will be communicated through a Market Notice at least 30 days prior to becoming effective.

When the shadow price cap for an IROL is determined based on the process in B, above, then the process outlined in Section 3.6, Methodology for Setting Transmission Shadow Price Caps for Irresolvable Constraints in SCED, does not apply to the IROL.

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 LMP 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 PUCT 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 LMP 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 PUCT 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 equal to the effective Value of Lost Load (VOLL) plus the effective Real-Time System-Wide Offer Cap (RTSWCAP) plus $0.01/MWh. 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 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 HDLs 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 LDLs 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, Load Frequency Control (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 Ancillary Service and the cost to the Load Serving Entities (LSEs). 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 HDL and a 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 Qualified Scheduling Entity (QSE) for its Generation Resources subject to the following. A proxy EOC is created in the SCED process if the QSE submitted EOC does not extend from LSL to HSL (in this case SCED extends the submitted EOC as described in 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 the table below. The SCED over-generation Power Balance Penalty curve will be set to System-Wide Offer Floor.

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	HCAP plus 1

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 Shift Factor 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 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, Congestion Revenue Right (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 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 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, Congestion Revenue Right (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
Regulation Up	SWCAP
Responsive Reserve	SWCAP minus 0.01
Non-Spin Reserve	SWCAP minus 0.03
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

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 Ancillary Service, as specified in the Ancillary Service Plan, and the amount of the self-arranged AS. The value of the Ancillary Service penalty factors are chosen to allow the selection of Ancillary Service offers that result in the least amount of deficit considering the maximum Ancillary Service penalty factors referenced in Appendix 2, Table 2-1 for each given Ancillary Service over the Operating Day and to assign a priority to the Ancillary Service constraints relative to the enforcement of the Power Balance and Network Transmission constraints. Additionally, the increasing penalty cost structure from Non-Spinning Reserve (Non-Spin) Ancillary Service to Regulation Ancillary Service prioritizes the DAM Ancillary Service procurement as first Regulation Services, then Responsive Reserve (RRS), and lastly Non-Spin. In other words multiple offers from the same resource will be considered in the rank order given. Notably however, the Ancillary Service penalty factors are not used to set the Market Clearing Price for Capacity (MCPC) for each Ancillary Service. Instead, the infeasible Ancillary Service requirement amounts are reduced to the feasible level and the DAM clearing is rerun so that the price of the last Ancillary Service awarded MW sets the MCPC for each Ancillary Service. The Ancillary Service penalty factors used in DAM are also used in the Supplemental Ancillary Services 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 Ancillary Service 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

NPRR Number	1230	NPRR Title	Methodology for Setting Transmission Shadow Price Caps for an IROL in SCED
Impact Analysis Date	May 7, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) 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
None.

Board Report

NPRR Number	1231	NPRR Title	FFSS Program Communication Improvements and Additional Clarifications
Date of Decision	August 20, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Less than $5K (Operations & Maintenance (O&M)) Project Duration: No project required		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	3.14.5, Firm Fuel Supply Service 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) provides additional clarifications and improvements to the Firm Fuel Supply Service (FFSS) process. The changes in the NPRR include: • Modifying the procedure for the fuel restocking process; • Modifying the method by which the Qualified Scheduling Entity (QSE) notifies ERCOT of an approved alternate Generation Resource replacing a Firm Fuel Supply Resource (FFSSR) during the FFSS obligation period; • Extending the deadline for the ERCOT required FFSS deployment report to TAC from 30 days to 45 days; • Clarifying when a Resource is considered available for Settlement purposes;		

	• Removing duplicative language for the disqualification of an FFSSR due to the prior implementation of the decertification process; and • Clarifies the decertification of an FFSSR can occur due to actions throughout the entire FFSS obligation period and an accumulation from prior periods.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	During the 2023-2024 FFSS obligation period, a few processes and clarifications were identified as areas of needed improvement. The first includes modifications to two existing procedures. The first procedure modification is to be observed in the circumstance where the QSE has requested or ERCOT has instructed the QSE to restock their fuel reserve after an FFSS deployment. The communication regarding the request to restock and the approval from ERCOT will be handled via the email account FFSS@ercot.com. The second procedure modification proposed includes a change to the method by which the QSE communicates to ERCOT when the QSE is changing the FFSS Resource (FFSSR) designation among the primary and alternate Generation Resource(s). Currently, the QSE is required to call the ERCOT Control Room and notify an Operator of this change. ERCOT proposes the QSE send an email to FFSS@ercot.com and notify ERCOT of the change. Such email is required for all changes in the FFSSR, including reversion to the primary FFSSR. This will ensure that the Settlement for the primary FFSSR is based on the appropriate Resource's Availability Plan. Both of these changes will provide additional transparency to

	ERCOT and will ensure that the FFSSR is settled appropriately when calculating the FFSS Hourly Rolling Equivalent Availability Factor. Next, ERCOT is required to produce a report to the Technical Advisory Committee (TAC), or its designated subcommittee, within 30 days following the end of the FFSS obligation period with details of the FFSS deployments. ERCOT is proposing extending this deadline to 45 days to allow additional time to gather the information needed for this report. Additionally, ERCOT revises the provisions regarding disqualification to provide FFSS that are no longer needed with the implementation of NPRR1167, Improvements to Firm Fuel Supply Service Based on Lessons Learned. The process for decertification of an FFSSR has now been in place for an obligation period, eliminating the needed for these stop gap provisions that mirrored the grounds for decertification. In addition, changes have been made to the decertification language to clarify that if an FFSSR fails to meet provisions (a) and (b) in paragraph (18) of Section 8.1.1.2.1.6 across any FFSS obligation period, or fails to meet provision (c) through the entire FFSS Obligation period, the FFSSR is subject to decertification. Finally, clarifications have been made to specify the events in which the FFSSR will be considered available for the purposes of calculating the FFSS Hourly Rolling Equivalent Availability Factor. These include the situations when the FFSSR has exhausted all of its fuel following an FFSS deployment and it was approved to restock, the FFSSR has exhausted all of its fuel but ERCOT has not approved a fuel restock, or if the FFSSR has exhausted all of its emissions hours allocated to the FFSSR per the FFSS Offer Submission Form.
PRS Decision	On 6/13/24, PRS voted unanimously to recommend approval of NPRR1231 as amended by the 6/12/24 ERCOT comments. All Market Segments participated in the vote. On 7/18/24, PRS voted unanimously to endorse and forward to TAC the 6/13/24 PRS Report and 5/7/24 Impact Analysis for NPRR1231. All Market Segments participated in the vote.
Summary of PRS Discussion	On 6/13/24, ERCOT staff provided an overview of NPRR1231, and participants reviewed the 6/6/24 Luminant comments, the 6/10/24 ERCOT comments, and the 6/12/24 ERCOT comments. On 7/18/24, participants reviewed the 5/7/24 Impact Analysis for NPRR1231.

Board Report

TAC Decision	On 7/31/24, TAC voted unanimously to recommend approval of NPRR1231 as recommended by PRS in the 7/18/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 7/31/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 8/20/24, the ERCOT Board voted unanimously to recommend approval of NPRR1231 as recommended by TAC in the 7/31/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1231 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1231.
ERCOT Opinion	ERCOT supports approval of NPRR1231.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1231 and believes the market impact for this NPRR implements effective improvements to the FFSS program which can be implemented before the 2024/2025 FFSS obligation period begins.

Sponsor	
Name	Magie Shanks / Marcelo Magarinos
E-mail Address	magie.shanks@ercot.com / marcelo.magarinos@ercot.com
Company	ERCOT
Phone Number	512-248-6472 / 512-248-6724

Board Report

Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
E-Mail Address	cory.phillips@ercot.com
Phone Number	512-248-6464

Comments Received	
Comment Author	**Comment Summary**
Luminant 060624	Proposed redlines to introduce the concept of lending fuel from other Resources to FFSSR sites to speed up restocking after a deployment, modify the process to involve a notification to ERCOT rather than a request, and shorten the timeline for providing restocking estimates to ERCOT
ERCOT 061024	Responded to the 6/6/24 Luminant comments, expressing concerns with potential gaming resulting from QSEs shifting fuel between Resources within their portfolio
ERCOT 061224	Provided additional redlines to clarify the timeline for providing ERCOT with restocking timeline estimates, and requested other improvement ideas raised by Luminant be addressed in a separate NPRR

Market Rules Notes

Please note the baseline Protocol language in the following sections has been updated to reflect the incorporation of the following NPRRs into the Protocols:

- NPRR1228, Continued One-Winter Procurements for Firm Fuel Supply Service (FFSS) (incorporated 8/1/24)
    - Section 3.14.5

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

- NPRR1241, Firm Fuel Supply Service (FFSS) Availability and Hourly Standby Fee
    - Section 8.1.1.2.1.6

Proposed Protocol Language Revision

3.14.5 *Firm Fuel Supply Service*

(1) Each Generation Resource providing or offering to provide Firm Fuel Supply Service (FFSS), including the primary and any alternate Generation Resources identified in the FFSS Offer Submission Form, must meet technical requirements specified in Section 8.1.1, QSE Ancillary Service Performance Standards, and Section 8.1.1.1, Ancillary Service Qualification and Testing.

(2) ERCOT shall issue an RFP by August 1 of each year soliciting offers from QSEs for Generation Resources to provide FFSS. The RFP shall require offers to be submitted on or before September 1 of each year.

(3) QSEs may submit offers individually for one or more Generation Resources to provide FFSS using the FFSS Offer Submission Form posted on the ERCOT website. A QSE may not submit an offer for a given Generation Resource unless it is the QSE designated by the Resource Entity associated with that Generation Resource. ERCOT must evaluate offers using criteria identified in an appendix to the RFP. ERCOT will issue FFSS awards by September 30 and will post the awards to the MIS Certified Area for each QSE that is awarded an FFSS obligation. The posting will include information such as, but not limited to, the identity of the primary Generation Resource and any alternate Generation Resource(s), the FFSS clearing price, the amount of reserved fuel associated with the FFSS award, the MW amount awarded, and the Generation Resource's initial minimum LSL when providing FFSS. The RFP awards shall cover a period beginning November 15 of the year in which the RFP is issued and ending on March 15 of the year after the year in which the RFP is issued. A QSE may submit an offer for one or more Generation Resources to provide FFSS beginning in the same year the RFP is issued or as otherwise specified in the RFP. An FFSS Resource (FFSSR) shall be considered an FFSSR and is required to provide FFSS from November 15 through March 15 for each year of the awarded FFSS obligation period. ERCOT shall ensure FFSSRs are procured and deployed as necessary to maintain ERCOT System reliability during, or in preparation for, a natural gas curtailment or other fuel supply disruption.

(a) On the FFSS Offer Submission Form, the QSE shall disclose information including, but not limited to, the Generation Resource and any alternate Generation Resource(s), the amount of reserved fuel offered, the MW available from the capacity offered, an estimate of the time to restock fuel reserves, and each limitation of the offered Generation Resource that could affect the Generation Resource's ability to provide FFSS.

(b) If the QSE offers a Generation Resource as meeting the qualification requirements in paragraph (1)(c) of Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification, the QSE must submit as part of its offer a certification for the offered Generation Resource. The certification must include:

(i) Certification that the Generation Entity for the Generation Resource (or an Affiliate) has a Firm Transportation Agreement, firm natural gas supply, and contracted or owned storage capacity meeting the qualification requirements in paragraph (1)(c) of Section 8.1.1.2.1.6;

(ii) The following information regarding the Firm Transportation Agreement:

(A) FFSS Qualifying Pipeline name;

(B) Term;

(C) Primary points of receipt and delivery;

(D) Maximum daily contract quantity (in MMBtu);

(E) Shipper of record; and

(F) Whether the Firm Transportation Agreement provides for ratable receipts and deliveries; and

(iii) The following information regarding the storage arrangements:

(A) Storage facility name;

(B) Term of the Firm Gas Storage Agreement (if applicable);

(C) Maximum storage quantity owned or contracted under the Firm Gas Storage Agreement (in MMBtu); and

(D) Maximum daily withdrawal quantity (in MMBtu).

(c) For a Generation Resource to be eligible to receive an FFSS award, the primary Generation Resource and any alternate Generation Resource(s) identified in the FFSS Offer Submission Form shall complete all applicable testing requirements as specified in Section 8.1.1.2.1.6. A QSE representing an FFSSR is allowed to provide the FFSS with an alternate Resource previously approved by ERCOT to replace the FFSSR.

(d) An offer to provide FFSS is an offer to supply an awarded amount of capacity, maintain a sufficient amount of reserved fuel to meet that award for the duration requirement specified in the RFP, and to designate a specific number of emissions hours that will be reserved for the awarded FFSSR in meeting its obligation to perform in the event that FFSS is deployed. Reserved fuel, emissions hours, and other attributes, in excess of what is needed to meet the FFSS obligation can be used at the discretion of the QSE as long as sufficient fuel reserves and emissions hours are maintained for the purposes of ERCOT deployment of FFSS.

(e) Within ten Business Days of issuing FFSS awards, ERCOT will post on the ERCOT website the identity of all Generation Resources that were offered as primary Generation Resources or alternate Generation Resources to provide FFSS for the most recent procurement period, including prices and quantities offered.

(4) The QSE for an FFSSR shall ensure that the Resource is prepared and able to come On-Line or remain On-Line in order to maintain Resource availability in the event of a natural gas curtailment or other fuel supply disruption.

(a) When ERCOT issues a Watch for winter weather, ERCOT will notify all Market Participants, including all QSEs representing FFSSRs, to begin preparation for potential FFSS deployment. Such preparation may include, but is not limited to, circulation of alternate fuel to its facilities, if applicable; heat fuel oil to appropriate temperatures, if applicable; call out additional personnel as necessary, and be ready to receive a Dispatch Instruction to provide FFSS. An FFSSR may begin consuming a minimum amount of alternate fuel to validate it is ready for an FFSS deployment.

(b) In anticipation of or in the event of a natural gas curtailment or other fuel supply disruption to an FFSSR, the QSE shall notify ERCOT as soon as practicable and may request approval to deploy FFSS to generate electricity. ERCOT shall evaluate system conditions and may approve the QSE's request. The QSE shall not deploy the FFSS unless approved by ERCOT. Upon approval to deploy FFSS, ERCOT shall issue an FFSS VDI to the QSE. ERCOT may issue separate VDIs for each Operating Day for each FFSSR that is deployed for FFSS.

(c) In conjunction with a QSE notification under paragraph (b) above, the QSE shall also report to ERCOT any environmental limitations that would impair the ability of the FFSSR to provide FFSS for the required duration of the FFSS award.

(d) ERCOT may issue an FFSS VDI without a request from the QSE, however ERCOT shall not issue an FFSS VDI without evidence of an impending or actual fuel supply disruption affecting the FFSSR.

(e) If the FFSSR is generating at a level above the FFSS MW awarded amount and that level of output cannot be sustained for the required duration of the FFSS award, ERCOT may use a manual High Dispatch Limit (HDL) override to ensure the FFSSR can continue to generate at the FFSS MW award level for the entire FFSS duration requirement specified in the RFP.

(f) The FFSSR shall continuously deploy FFSS to generate electricity until the earlier of (i) the exhaustion of the fuel reserved to generate at the FFSS MW award level for the duration requirement specified in the RFP, including any fuel that was restocked following approval or instruction from ERCOT, (ii) the fuel supply disruption no longer exists, or (iii) ERCOT determines the FFSS deployment is no longer needed. Upon satisfying one of these qualifications, ERCOT shall terminate the VDI. ~~and~~ In the event of (i), the FFSSR shall not be obligated to continue ~~its~~being available for FFSS deployment for the remainder of the Watch.

In the event of (ii) or (iii), the FFSSR shall continue being available for FFSS deployment for the remainder of the Watch.

(g) The QSE for the FFSSR is responsible for communicating with the ERCOT control room the anticipated exhaustion of the reserved fuel at least six hours before that anticipated exhaustion and upon the exhaustion of that fuel.

(h) A QSE shall notify the ERCOT control room of the anticipated exhaustion of emissions credits or permit allowances at least six hours before the exhaustion of those credits or allowances. Upon receiving such notification, ERCOT shall modify the VDI so the FFSS deployment is terminated upon exhaustion of those credits or allowances.

(i) Upon deployment or recall of FFSS, ERCOT shall notify all Market Participants that such deployment or recall has been made, including the MW capacity of service deployed or recalled.

(5) Following the deployment of FFSS, the QSE for an FFSSR may request ~~an~~ approval from ERCOT via email to FFSS@ercot.com, or ERCOT may instruct the QSE to restock their fuel reserve to restore their ability to generate at the FFSS MW award level for the duration requirement specified in the RFP~~.~~ as follows:

(a) The QSE requests preliminary approval from ERCOT control room, or ERCOT provides preliminary instruction, to restock and provide ERCOT an initial estimated timeline to complete the refueling.

(b) After receiving preliminary approval or instruction from ERCOT, the QSE shall:

(i) Immediately provide a final estimate for completing the restocking of fuel; or

(ii) Within 24 hours ~~of receiving preliminary approval or instruction from ERCOT to restock, the QSE shall~~ notify the ERCOT control room with an updated estimated timeline to complete the restocking of the fuel.

(c) Based on the most recent expected time needed to restock the fuel, the ERCOT control room may or may not provide final approval for restocking of the fuel.

(d) If ERCOT makes final approval to restock the fuel, the QSE representing the FFSSR shall inform the ERCOT control room immediately when restocking is complete.

(6) Following final approval from ERCOT, a QSE must restock their fuel reserve to restore their ability to generate at the FFSS MW award level for the specified duration requirement. In the event ERCOT does not receive the request to restock from a QSE representing an FFSSR, but the QSE no longer has sufficient reserved fuel to generate at the FFSS MW award level for the specified duration requirement, the QSE shall

communicate to the ERCOT control room this reduced capability and ERCOT may instruct the QSE to restock the fuel reserve as described in paragraph (5) above.

(7~~6~~) For a Resource to be considered as an alternate for providing FFSS, the following requirements must be met. The alternate Resource must:

(a) Be able to provide net real power sufficient to generate at the same FFSS MW award level as the primary Resource for the duration requirement specified in the RFP;

(b) Be a single Generation Resource, as registered with ERCOT; and

(c) Use the same source of fuel reserve for providing FFSS as the primary Resource.

(8~~7~~) An FFSS Offer Submission Form may have up to three alternate Generation Resources per primary Resource offering to provide FFSS.

(9~~8~~) For FFSSRs with approved alternate Generation Resources, if the FFSSR becomes unavailable, the QSE must:

(a) As soon as practicable, ~~call the ERCOT control room~~notify ERCOT via email to FFSS@ercot.com and inform ~~an Operator~~ERCOT that the FFSSR will be replaced by one of the alternate Generation Resources, specify which alternate Generation Resource (if multiple alternate Generation Resources have been designated), and provide an estimate of how long the replacement will be in effect;

(b) Update the Availability Plans for these Generation Resources to reflect current operating conditions within 60 minutes after identifying the change in availability of the FFSSR; and

(c) Update the COPs for these Generation Resources within 60 minutes after identifying the change in availability of the FFSSR.

(10) For FFSSRs that were replaced by one of their approved alternate Generation Resources, when the primary Resource is once again the FFSSR, the QSE must notify ERCOT of the change via email to the email address provided in paragraph (9)(a) above as soon as practicable.

(11~~9~~) An FFSSR providing BSS must have sufficient fuel reserved to generate at the FFSS MW award level for the duration requirement specified in the RFP in addition to any fuel required for the Generation Resource to meet the contracted BSS obligation. Any remaining fuel reserve in addition to that required for meeting FFSS and BSS obligations can be used at the QSE's discretion.

(12~~0~~) If ERCOT issues an FFSS VDI to an FFSSR for the same Operating Hour where a RUC instruction was issued, then for Settlement purposes ERCOT will consider the RUC instruction as cancelled.

(13~~1~~) If FFSS is deployed, then ERCOT will provide a report to the TAC or its designated subcommittee within 45~~30~~ days of the end of the FFSS obligation period. The report must include the Resources deployed and the reason for any deployments.

(14~~2~~) Any QSE that submits an offer or receives an award for a SWGR to provide FFSS, and the Resource Entity that owns or controls that SWGR, shall:

(a) Not nominate the SWGR to satisfy supply adequacy or capacity planning requirements in any Control Area other than the ERCOT Region during the period of the FFSS obligation; and

(b) Take any further action requested by ERCOT to ensure that ERCOT will be classified as the "Primary Party" for the SWGR under any agreement between ERCOT and another CAO during the period of the FFSS obligation.

(15~~3~~) On an annual basis after the FFSS season, ERCOT will provide a report separately for the total amounts from Section 6.6.14.1, Firm Fuel Supply Service Fuel Replacement Costs Recovery, and Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery, to the TAC or its designated subcommittee.

6.6.14.2 Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery

(1) ERCOT shall pay the FFSS Hourly Standby Fee to the QSE representing the primary Generation Resource. This standby fee is determined through a competitive bidding process, with an adjustment for reliability based on an Hourly Rolling Equivalent Availability Factor, as well as adjustments for capacity and deployment.

(2) The FFSSR will be considered available when calculating the FFSS Hourly Rolling Equivalent Availability Factor:

(a) During each non-FFSS deployment hour for which the FFSSR shows available in its Availability Plan;

(b) During any successful FFSS deployment of the FFSSR in which the FFSSR shows available in its Availability Plan; ~~and~~

(c) If the reserved fuel was exhausted during an FFSS deployment, starting the hour after the FFSSR has consumed all the fuel reserved to provide FFSS, through ~~during~~ the ~~period~~ approved hours when reserved fuel for FFSS is being restocked following ~~an instruction or~~ a final approval from ERCOT to do so, per paragraph (5) of Section 3.14.5, Firm Fuel Supply Service;~~.~~

(d) ~~Additionally, i~~In the event the FFSSR has consumed all the fuel reserved to provide FFSS and ERCOT does not issue an instruction or approval to restore FFSS capability, the FFSSR shall be considered to be available ~~for Settlement purposes~~ for the remainder of the FFSS obligation period in progress; or~~.~~

(e) If the FFSSR was deployed to provide FFSS and, as a result, has exhausted its emission hours allocated for the FFSSR, as specified in the FFSS Offer Submission Form.

(3) The FFSS Hourly Standby Fee is subject to reduction and claw-back provisions as described in Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification.

(4) ERCOT shall pay an FFSS payment to each QSE for each FFSSR. The FFSS payment for each hour of November 15, through March 15, i.e., during the FFSS obligation period, is calculated as follows:

$$\mathbf{FFSSAMT}_{q,r,h} = (-1) * (\mathbf{FFSSSBF}_{q,r,h} + \mathbf{FFSSFRC}_{q,r,h})$$

Where:

$$FFSSSBF_{q,r,h} = FFSSAWARD_{q,r,h} * FFSSCRF_{q,r,h} * FFSSARF_{q,r,h} * (1 - FFSSDRP_{q,r,h})$$

$$FFSSAWARD_{q,r,h} = FFSSPR_{q,r,h} * FFSSACAP_{q,r,h}$$

And:

FFSS Capacity Reduction Factor

If ($FFSSTCAP_{q,r,h} \geq FFSSACAP_{q,r,h}$)

Then: $FFSSCRF_{q,r,h} = 1$

Otherwise: $FFSSCRF_{q,r,h} = \text{Max}(0, 1 - 2 * (FFSSACAP_{q,r,h} - FFSSTCAP_{q,r,h}) / FFSSACAP_{q,r,h})$

FFSS Availability Reduction Factor

If ($FFSSHREAF_{q,r,h} \geq 0.90$)

Then: $FFSSARF_{q,r,h} = 1$

Otherwise: $FFSSARF_{q,r,h} = \text{Max}(0, 1 - (0.90 - FFSSHREAF_{q,r,h}) * 2)$

FFSS Hourly Rolling Equivalent Availability Factor

$$FFSSHREAF_{q,r,h} = \sum_{hr=h-1451}^{h}(\max(AVCAP_{q,r,hr})) / \sum_{hr=h-1451}^{h}(FFSSACAP_{q,r,hr})$$

Where,

If the Resource is a Combined Cycle Train:

$$\text{AVCAP}_{q,\,r,\,hr} = \max_{train,hr}\left(\max(\text{FFSEDFLAG}_{q,\,train,\,hr},\ \text{FFSSAFLAG}_{q,\,ccgr,\,hr}) * \min(\text{HSL}_{q,\,ccgr,\,hr},\ \text{FFSSACAP}_{q,\,train,\,hr})\right)$$

Otherwise:

$$\text{AVCAP}_{q,\,r,\,hr} = \max(\text{FFSEDFLAG}_{q,\,r,\,hr},\ \text{FFSSAFLAG}_{q,\,r,\,hr}) * \min(\text{HSL}_{q,\,r,\,hr},\ \text{FFSSACAP}_{q,\,r,\,hr})$$

Availability for a Combined Cycle Train will be determined pursuant to terms set forth in the RFP but no more than once per hour.

The above variables are defined as follows:

Variable	Unit	Definition
FFSSAMT $_{q,\,r,\,h}$	$	*Firm Fuel Supply Service Amount per QSE per Resource by hour*—The payment to QSE *q* assigned to the FFSS for the primary Generation Resource *r*, for the hour, calculated each hour of November 15 through March 15 during the awarded FFSS obligation period. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
FFSSAWARD $_{q,\,r,\,h}$	$	*Firm Fuel Supply Service Award Amount per QSE by hour*—The payment to the QSE *q* for the FFSS awarded to the primary Generation Resource *r* for each hour *h*, during the awarded FFSS obligation period. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
FFSSPR $_{q,\,r,\,h}$	$/MW per hour	*Firm Fuel Supply Service Price per QSE per Resource by hour*—The standby price of the primary Generation Resource *r* represented by QSE *q*, as specified in the FFSS award. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
FFSSCRF $_{q,\,r,\,h}$	none	*Firm Fuel Supply Service Capacity Reduction Factor per QSE per Resource by hour*—The capacity reduction factor assigned to the primary Generation Resource *r*, represented by QSE *q*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
HSL $_{q,\,r,\,hr}$	MW	*High Sustained Limit*—The HSL of the primary Generation Resource or the alternate Generation Resource *r* represented by QSE *q* as submitted in the COP, for the hour *h*. Where for a combined cycle Resource *r* is a Combined Cycle Generation Resource.
FFSSFRC $_{q,\,r,\,h}$	$ per hour	*Firm Fuel Supply Service Fuel Replacement Cost*—The fuel costs and fees to replace the burned fuel by the FFSSR, not recovered during the FFSS deployment period, paid to the primary Generation Resource *r* represented by QSE *q* for each FFSS instructed hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Definition
$FFSSDRP_{q, r, h}$	none	*Firm Fuel Supply Service Deployment Reduction Percentage*—The percentage of the Firm Fuel Supply Service Standby Fee subject to clawback per paragraphs (9) through (16) of Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification, for the QSE *q*, assigned to the primary Generation Resource *r*, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$FFSSSBF_{q, r, h}$	$	*Firm Fuel Supply Service Standby Fee per QSE per Resource by hour*—The standby fee to QSE *q* for the FFSS assigned to the primary Generation Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$FFSSTCAP_{q, r, h}$	MW	*Firm Fuel Supply Service Testing Capacity per QSE per Resource*—The tested capacity of the primary Generation Resource *r*, represented by QSE *q*, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$FFSSACAP_{q, r, hr}$	MW	*Firm Fuel Supply Service Awarded Capacity per QSE per Resource*—The awarded FFSS capacity of the primary Generation Resource *r*, represented by QSE *q* as specified in the FFSS award, applicable to each hour of November 15 through March 15 during the awarded FFSS obligation period. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$FFSSARF_{q, r, h}$	none	*Firm Fuel Supply Service Availability Reduction Factor per QSE per Resource by hour*—The availability reduction factor assigned to the primary Generation Resource *r* represented by QSE *q* for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$FFSSHREAF_{q, r, h}$	none	*Firm Fuel Supply Service Hourly Rolling Equivalent Availability Factor per QSE per Resource by hour*—The equivalent availability factor assigned to the primary Generation Resource *r* represented by QSE *q* over 1,452 hours, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$FFSSAFLAG_{q, r, hr}$	none	*Firm Fuel Supply Service Availability Flag per QSE per Resource by hour*—The flag of the availability assigned to the primary Generation Resource or the alternate Generation Resource *r* represented by QSE *q*, 1 for available and 0 for unavailable, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$FFSEDFLAG_{q, r, hr}$	none	*Firm Fuel Supply Event Deployment Flag per QSE per Resource by hour*—The flag ~~of successful FFSS deployment~~ assigned to the primary Generation Resource *r* ~~for the approved hours to restock reserved fuel for providing FFSS following the instruction or approval from ERCOT, or in the event the FFSSR has consumed all the fuel reserved to provide FFSS and ERCOT does not issue an instruction or approval to restock reserved fuel~~, represented by QSE *q*, that is used to determine if the FFSSR is considered available, as described in paragraph (2)(c) through (2)(e) above, 1 for ~~successful~~ available and 0 for ~~unsuccessful~~unavailable, for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.

Variable	Unit	Definition
AVCAP $_{q, r, hr}$	MW	*Available Capacity per Resource by hour*—The available capacity assigned to the primary Generation Resource *r* represented by QSE *q* as calculated for the hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	A primary or alternate Generation Resource approved by ERCOT to provide FFSS.
hr	none	The index of a given hour and the previous 1,451 hours counted only during each hour of November 15 through March 15 during the awarded FFSS obligation period.
h	none	The Operating Hour.
train	none	A Combined Cycle Train or an alternate Combined Cycle Train approved by ERCOT.
ccgr	none	A Combined Cycle Generation Resource within the Combined Cycle Train.

(5) The total of the payments to each QSE for all FFSSRs represented by this QSE for a given hour is calculated as follows:

$$\textbf{FFSSAMTQSETOT}_{q} = \sum_{r} \textbf{FFSSAMT}_{q,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
FFSSAMTQSETOT $_{q}$	$	*Firm Fuel Supply Service Amount QSE Total per QSE*—The total of the payments to QSE *q* for FFSS provided by all the FFSS Resources represented by this QSE for the hour.
FFSSAMT $_{q, r}$	$	*Firm Fuel Supply Service Amount per QSE per Resource*—The payment to QSE *q* for the FFSS assigned to the primary Generation Resource *r*, for the hour, calculated each hour of November 15 through March 15 during the awarded FFSS obligation period. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	A primary or alternate Generation Resource approved by ERCOT to provide FFSS.

8.1.1.2.1.6 Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification

Commented [CP1]: Please note NPRR1241 also proposes revisions to this section.

(1) Generation Resources that meet the following requirements are eligible to provide Firm Fuel Supply Service (FFSS) and may be selected in the procurement process for FFSS. Both the primary Generation Resource and any alternate Generation Resources, as specified in the FFSS Offer Submission Form, must meet the following requirements prior to submitting an FFSS Offer Submission Form:

(a) Successfully demonstrates dual fuel capability, the ability to establish and burn an alternative onsite stored fuel, and has onsite fuel storage capability in an amount that satisfies the minimum FFSS capability requirements, as described in paragraph (2) below;

(b) Has an onsite natural gas or fuel oil storage capability or off-site natural gas storage where the Resource Entity and/or QSE owns and controls the natural gas storage and pipeline to deliver the required amount of reserve natural gas to the Generation Resource from the storage facility in an amount that satisfies the minimum FFSS capability requirements, as defined in paragraph (2) below; or

(c) Meets the following requirements:

(i) The Generation Entity for the Generation Resource (or an Affiliate of such Generation Entity) either owns a storage facility with, or has a Firm Gas Storage Agreement for, sufficient natural gas storage capacity for the offered Generation Resource to deliver the offered MW for the duration requirement specified in the request for proposal (RFP);

(ii) The Generation Entity for the Generation Resource (or an Affiliate of such Generation Entity) must own and have good title to sufficient natural gas in the storage facility for the offered Generation Resource to deliver the offered MW for at least the duration requirement specified in the RFP, and must commit to maintain such quantity of natural gas in storage at all times during the obligation period; and

(iii) The Generation Entity for the Generation Resource (or an Affiliate of such Generation Entity) must have entered into a Firm Transportation Agreement on an FFSS Qualifying Pipeline, or multiple Firm Transportation Agreements on multiple Qualifying Pipelines, and:

(A) Each Firm Transportation Agreement must have a maximum daily contract quantity sufficient to transport the quantity of natural gas described above from the storage facility to the Generation Resource in a quantity that is sufficient to allow generation of the offered FFSS MW for at least the duration requirement specified in the RFP;

(B) At least one of the Firm Transportation Agreements must contain a primary receipt point that is the point of withdrawal for the storage facility used to comply with paragraph (i) above;

(C) At least one of the Firm Transportation Agreements must contain a primary delivery point that permits delivery of the natural gas directly to the Generation Resource (including through a plant line or other dedicated lateral);

(D) Each Firm Transportation Agreement must have a term that includes each hour of November 15 through March 15, i.e., during the FFSS obligation period; and

(E) If multiple Firm Transportation Agreements will be used, the point of delivery for each Firm Transportation Agreement, other than the Firm Transportation Agreement that satisfies the requirements set forth in paragraph (C) above, must be a primary receipt point under another Firm Transportation Agreement such that there is a complete path for firm transportation service from the storage facility to the Generation Facility.

(iv) If the Generation Entity will utilize a contractual right to firm gas storage capacity on a third-party system under a Firm Gas Storage Agreement to comply with paragraph (i) above rather than a self-owned physical gas storage facility to qualify, then the Firm Gas Storage Agreement must have:

(A) A term that includes each hour of November 15 through March 15, i.e., during the FFSS obligation period;

(B) A maximum storage quantity not less than the amount of natural gas needed to allow the Generation Resource to deliver the offered MW for the duration requirement specified in the RFP;

(C) A maximum daily withdrawal quantity that permits the Generation Entity (or an Affiliate) to withdraw from storage a daily quantity of natural gas sufficient to allow the Generation Resource to deliver the offered MW for the duration requirement specified in the RFP; and

(D) A point of withdrawal that is a primary receipt point under its Firm Transportation Agreement.

(v) If the Generation Entity will utilize storage owned by it or an Affiliate to comply with paragraph (i) above, then the Generation Entity must certify that for the entire obligation period it or its Affiliate, as applicable, retains the rights to:

(A) Sufficient storage capacity in its facility to store not less than the amount of natural gas needed to allow the Generation Resource to deliver the offered MW for the duration requirement specified in the RFP;

(B) Withdraw from its storage a daily quantity of natural gas sufficient to allow the Generation Resource to deliver the offered MW for the duration requirement specified in the RFP; and

(C) Withdraw from its storage facility at a point of withdrawal that is a primary receipt point under its Firm Transportation Agreement.

(vi) The MW offered by the QSE for the Generation Resource may not be less than the Generation Resource's LSL.

(vii) The Generation Entity for the Generation Resource may satisfy the requirements set forth in paragraphs (i) through (v) above through use of a single, bundled agreement providing for gas supply, storage, and transportation service, as long as the bundled agreement satisfies the requirements of the definitions of Firm Transportation Agreement and Firm Gas Storage Agreement, the requirements in paragraphs (ii), (iii)(A), (iii)(D), (iv)(A), (iv)(B), and (iv)(C) above, and has a primary delivery point that permits delivery of the gas directly to the Generation Resource (including through a plant line or other dedicated lateral).

(d) A Generation Resource may participate as a Firm Fuel Supply Service Resource (FFSSR) under only one of paragraphs (a), (b), or (c) above.

(e) Successfully demonstrates the ability to provide FFSS in order to maintain Resource availability in the event of a natural gas curtailment or other fuel supply disruption consistent with qualifying technologies identified by the Public Utility Commission of Texas (PUCT).

(2) The minimum FFSS capability requirement is the volume of fuel necessary to operate the Generation Resource at the FFSS MW award level for the duration requirement specified in the RFP. This MW value must be greater than or equal to the Generation Resource's LSL and is a limit on the MW quantity of FFSS that can be offered for the Generation Resource in the FFSS Offer Submission Form.

(3) A Generation Resource will not be considered qualified to provide FFSS if, in a prior obligation period, the Generation Resource was decertified per paragraph (18) below. ~~an FFSSR during a Watch for winter weather and the Generation Resource:~~

~~(a) Failed to come On-Line or stay On-Line during an FFSS deployment due to a fuel-related issue for two or more deployments;~~

~~(b) Came On-Line or continued to generate using reserved fuel during an FFSS deployment, but failed to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a fuel-related issue for two or more deployments; or~~

~~(c) Failed to maintain an Hourly Rolling Equivalent Availability Factor greater than or equal to 50%.~~

~~(d)~~ However, such Generation Resource may nevertheless be considered qualified to provide FFSS if the Generation Resource:

(a~~i~~) Has subsequently been recertified, as provided in paragraph (22) below; or (b~~ii~~) The QSE representing the Generation Resource submits a corrective action plan to ERCOT and has agreement with ERCOT on that plan.

(4) A Generation Entity may, but is not required to, submit in writing a proposed form of Firm Gas Storage Agreement or Firm Transportation Agreement (whether to be entered into by the Generation Entity or an Affiliate thereof) to ERCOT for review to be certified as an FFSS Qualified Contract in accordance with such policies and procedures as ERCOT may develop or require from time to time consistent with the requirements of the ERCOT Protocols.

(a) ERCOT may, but is not obligated to, undertake a review of such agreement and, if acceptable, certify in writing such agreement as an FFSS Qualified Contract. The decision whether to certify such agreement as an FFSS Qualified Contract shall be in ERCOT's sole discretion.

(b) To the extent that any such agreement is so certified by ERCOT, it shall constitute an FFSS Qualified Contract, and a Generation Entity may rely upon such certification for purposes of qualifying as an FFSSR under paragraph (1)(c) above. Any material change to the ERCOT certified form of an existing FFSS Qualified Contract that affects the requirements of a firm natural gas FFSSR shall require a re-certification by ERCOT. For the avoidance of doubt, a Firm Gas Storage Agreement or Firm Transportation Agreement meeting the requirements of the natural gas FFSSR is not required to be certified as an FFSS Qualified Contract.

(5) A QSE representing a Generation Resource that will be offered to provide FFSS as a primary Generation Resource or an alternate Generation Resource must annually demonstrate each offered Generation Resource's capability to use reserved fuel sources identified in paragraphs (1)(a) through (1)(c) above and sustain its output for 60 minutes at the MW value equal to the QSE's desired level of FFSS qualification for the Resource. The maximum MW of FFSS that can be offered for the designated Resource by the QSE must be limited to the average Real-Time net real power (in MW) telemetered for the Resource during the demonstration period. Each QSE representing an FFSSR or prospective FFSSR must annually complete the test or successfully deploy at the maximum awarded MW amount for at least the demonstration period and inform ERCOT by August 15 of each year. In order to complete this annual process, the QSE representing the Generation Resource(s) shall:

(a) If qualifying by a self-test, coordinate the test with the ERCOT control room and show the Resource as having a Resource Status of "ONTEST" in its COP and through its Real-Time telemetry for the duration of the demonstration; and

(b) Submit a Resource FFSS qualification form with the date and time of the self-test or the successful deployment that the QSE would like considered for qualification.

(6) A QSE representing an FFSSR must ensure the full awarded FFSS capability is available by November 15 of each year awarded in the RFP.

(7) A QSE representing an FFSSR shall update the Availability Plan for a Generation Resource to show it is unavailable to provide FFSS if it is not available to come On-Line or generate using reserved fuel. The QSE representing an FFSSR must submit an Availability Plan for any alternate Generation Resource that were designated in the FFSS Offer Submission Form. The QSE shall continue to show the Generation Resource is unavailable to provide FFSS in the Availability Plan until it can successfully come On-Line or generate using the reserved fuel.

(8) An FFSSR that is not available to come On-Line shall inform the ERCOT control room as soon as practicable and update the FFSSR Availability Plan within 60 minutes of identifying the unavailability.

(9) If the FFSSR is not available for the hours for which ERCOT has issued a Watch for winter weather, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 90 days, unless the FFSSR ~~successfully deployed for its entire FFSS award obligation~~<u>exhausted the fuel reserved to generate at the FFSS MW award level for the duration requirement specified in the RFP, including any fuel that was restocked following final approval or instruction from ERCOT, or the FFSSR</u> exhausted emission hours allocated for the FFSSR, as specified in the FFSS Offer Submission Form. Evidence of an FFSSR not being available includes, but is not limited to, an Availability Plan submission of unavailable or other communications to the ERCOT control room indicating the FFSSR is not available during the Watch.

(10) If the FFSSR fails to come On-Line or stay On-Line during an FFSS deployment due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 90 days. A QSE representing an FFSSR may coordinate with ERCOT and seek approval to take the FFSSR Off-Line for no more than four hours to perform critical maintenance associated with consuming the reserved fuel. If the QSE coordinates with ERCOT and receives approval to take the FFSSR unit Off-Line and brings the FFSSR back On-Line within four hours or less, this shall not count as failure to stay On-Line for the purpose of this paragraph.

(11) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment, but fails to telemeter on average an HSL equal to or greater than 95% of the awarded FFSS MW value due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 90 days, in proportion to the difference between the awarded MW value and the average telemetered HSL over the FFSS deployment period.

(12) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 90 days, in proportion to the difference between the average MW level instructed by

ERCOT over the FFSS deployment period and the corresponding average generation of the FFSSR.

(13) If the FFSSR fails to come On-Line or stay On-Line during an FFSS deployment due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 15 days.

(14) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to telemeter on average an HSL equal to or greater than 95% of the awarded FFSS MW value due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 15 days, in proportion to the difference between the awarded MW value and the average telemetered HSL over the FFSS deployment period.

(15) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 15 days, in proportion to the difference between the average MW level instructed by ERCOT over the FFSS deployment period and the corresponding average generation of the FFSSR.

(16) Notwithstanding paragraphs (9) through (15) above, if the FFSSR is otherwise available but fails to come On-Line or is forced Off-Line due to a transmission system outage or transmission system limitation that would prevent the unit from being deployed to LSL, ERCOT shall not claw back the FFSS Hourly Standby Fee.

(17) If conditions described in paragraphs (11) and (12) occur for the same deployment period, ERCOT shall only claw back the larger amount calculated in paragraph (11) or (12). If conditions described in paragraphs (14) and (15) occur for the same deployment period, ERCOT shall only claw back the larger amount calculated in paragraph (14) or (15).

(18) ERCOT shall decertify a primary Generation Resource or any alternate Generation Resource that was an FFSSR~~ during a Watch for winter weather~~ for any of the following:

(a) Failure to come On-Line or stay On-Line during an FFSS deployment due to a fuel-related issue for two or more deployments;

(b) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment, failure to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a fuel-related issue for two or more deployments; or

(c) Failure to maintain an Hourly Rolling Equivalent Availability Factor greater than or equal to 50%.

(19) If ERCOT decertifies a primary Generation Resource, the QSE shall designate an alternate Generation Resource that was awarded through the FFSS procurement process to replace the decertified Generation Resource and continue to provide FFSS. The designated alternate Generation Resource shall satisfy all of the requirements in paragraph (9~~8~~) of Section 3.14.5, Firm Fuel Supply Service. The designated alternate Generation Resource may no longer be an alternate for another primary Generation Resource.

(20) If ERCOT decertifies an FFSSR that does not have any alternate Generation Resources that were awarded through the FFSS procurement process, ERCOT will cease payments to the QSE under Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery, until the FFSSR is recertified by ERCOT. ERCOT may issue one or more RFPs to replace the decertified FFSSR's capacity for the remainder of the FFSS obligation period.

(21) If ERCOT has not replaced a decertified Generation Resource's FFSSR capacity, the QSE of a decertified Generation Resource may request to reestablish its FFSSR certification by submitting a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and by successfully passing a new test, as described in paragraph (5) above. ERCOT shall, in its sole discretion, determine whether a Generation Resource shall be recertified.

(22) A decertified Generation Resource that has not been recertified by ERCOT must submit a corrective action plan to ERCOT and have agreement with ERCOT on that plan in order to be considered qualified to provide FFSS and be selected in the procurement process for any future FFSS obligation period.

(23) If an FFSSR is unavailable or fails to continuously deploy due to a Force Majeure Event, the Generation Entity for such Generation Resource must provide a report to ERCOT containing certain additional information, including:

(a) If the basis of the non-performance is a Force Majeure Event affecting the FFSSR, a description of the Force Majeure Event giving rise to the non-performance, with reasonably full details of such Force Majeure Event;

(b) If the basis of the non-performance is the unavailability of the FFSSR's FFSS Qualifying Pipeline or natural gas storage facility:

(i) A copy of the relevant Firm Transportation Agreement and/or Firm Gas Storage Agreement;

(ii) A copy of the nominations submitted or a detailed accounting of no notices volumes delivered for the gas day prior to the Force Majeure Event until the gas day after the Force Majeure Event;

(iii) The applicable storage inventory level for the gas day prior to the Force Majeure Event until the gas day after the Force Majeure Event;

(iv) A copy of the force majeure notice from the FFSS Qualifying Pipeline operator or storage provider; and

(v) The capacity and flow data from the FFSS Qualifying Pipeline or storage facility for the gas day prior to the Force Majeure Event until the gas day after the Force Majeure Event;

(c) To the best of its knowledge, how, why, and to what extent the Force Majeure Event actually and directly affected the FFSSR's ability to perform;

(d) The FFSSR's heat rate;

(e) The applicable nominations, and if applicable, no-notice delivered, on the FFSS Qualifying Pipeline from the gas day prior to the Force Majeure Event until the day after the Force Majeure Event; and

(f) ERCOT will have the right to request that the Generation Entity provide, or cause to be provided, any additional information ERCOT deems necessary, and the Generation Entity must provide such requested information to the extent reasonably within its possession or control. If the information is not in the possession of the Generation Entity (or its Affiliate) but may be in the possession of the FFSS Qualifying Pipeline operator or storage provider, the Generation Entity will exercise any contractual rights it has to request such information from the FFSS Qualifying Pipeline operator or storage provider, as applicable.

(24) Unless the agreement is a certified contract, if the relevant Firm Transportation Agreement and/or Firm Gas Storage Agreement does not ensure firmness in the manner required by the ERCOT Protocols, ERCOT shall revoke the award and claw back and/or withhold all of the FFSS Hourly Standby Fees for all of the days of the obligation period.

(25) For an FFSSR, a Force Majeure Event will be treated the same as any other cause for unavailability for the purposes of calculating the FFSSR's FFSS Hourly Rolling Equivalent Availability Factor and for paragraphs (9) through (15) above.

(26) It will constitute a material change under the ERCOT Protocols if a primary Generation Resource or any alternate Generation Resource that qualified to provide FFSS under paragraph (1)(c) above ceases to satisfy any of the requirements to qualify as an FFSSR under paragraph (1)(c) above (for example, but not limited to, if the Firm Transportation Agreement is terminated or if the FFSS Qualifying Pipeline no longer qualifies as an FFSS Qualifying Pipeline).

(a) The QSE of such Generation Resource will be required to notify ERCOT within two Business Days of such a material change.

(b) ERCOT may decertify a primary Generation Resource or alternate Generation Resource if such material change is, in ERCOT's sole opinion, an adverse change (for example, but not limited to, if a Firm Transportation Agreement is terminated and not replaced with a comparable, qualifying Firm Transportation Agreement).

ERCOT Impact Analysis Report

NPRR Number	**1231**	**NPRR Title**	**FFSS Program Communication Improvements and Additional Clarifications**
Impact Analysis Date	May 7, 2024		
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 within 1-2 weeks following Public Utility Commission of Texas (PUCT) 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	ERCOT will update grid operations and practices to implement this NPRR.		

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

Comments
This NPRR will require desk procedure updates and operator training.

Board Report

NPRR Number	<u>1233</u>	NPRR Title	Modification of Weatherization Inspection Fees on the ERCOT Fee Schedule
Date of Decision	August 20, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	First of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	ERCOT Fee Schedule		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) adds a flat fee for federally owned generation units, and adjusts the weatherization inspection fee for Transmission Service Providers (TSPs).		
Reason for Revision	☒ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive		

Board Report

	(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)
Justification of Reason for Revision and Market Impacts	Pursuant to 16 Texas Administrative Code § 25.55, Weather Emergency Preparedness, ERCOT is required to perform weatherization tasks, including conducting inspections of Generation Resources and Transmission Facilities. In NPRR1107, Addition of Weatherization Inspection Fees to the ERCOT Fee Schedule and Clarification of Generation Interconnection Request Fees, ERCOT revised the ERCOT Fee Schedule to include weatherization inspection fees for Resource Entities with Generation Resources or Energy Storage Resources (ESRs), as well as TSPs. Under the current fee schedule, the weatherization inspection fee charged to each Resource Entity is based on that Resource Entity's MW capacity as a percentage of ERCOT's total capacity, regardless of whether an inspection actually takes place during an inspection cycle. This allocation method has prevented collection of inspection fees for some federally owned Generation Resources because federal policy only permits payment for benefits actually received. Charges assessed by an entity (including a state) against a federal facility must be a fair approximation of the cost of benefits actually received by the United States. Said differently, federally owned Generation Resources are not permitted to pay weatherization inspection fees unless an inspection takes place. Accordingly, the federal government has refrained from paying weatherization inspection fee charges when federally owned Generation Resources are not actually inspected during a given inspection cycle. As a solution to this issue, ERCOT proposes a specific fee for each actual inspection of a federally owned Generation Resource based on the average to-date cost per inspection for all Resource Entities and TSPs of $4,475.04, which has been rounded to $4,500 for inclusion in the revised fee schedule. The reasoning underlying this proposed revision is consistent with the PUCT's order in Docket No. 23220, in which ERCOT was ordered to revise its Protocols to exempt certain federally owned Resources from signing the ERCOT Standard Form Agreement as a result of sovereignty concerns. That order resulted in the adoption of Protocol Section 16.5.1.2, Waiver for Federal Hydroelectric Facilities, which creates a waiver of certain registration requirements for federally owned Generation Resources. Additionally, ERCOT proposes TSP inspection fees be increased to the same $4,500 average cost per inspection, rather than the current $3,000 rate per inspection, in order to more accurately align the fee with actual costs incurred by ERCOT.

	Finally, because ERCOT maintains a number of different databases that contain the information that ERCOT can use to track MW capacity within ERCOT, ERCOT proposes to take out the reference to its use of Resource Integration and Ongoing Operations-Resource Services ("RIOO-RS") for its calculations. This gives ERCOT the ability to use a different database if necessary, or in the event that RIOO-RS is renamed in the future, to continue to use that database without an NPRR to update the name that appears in the ERCOT Fee Schedule.
PRS Decision	On 6/13/24, PRS voted unanimously to recommend approval of NPRR1233 as submitted. All Market Segments participated in the vote. On 7/18/24, PRS voted unanimously to endorse and forward to TAC the 6/13/24 PRS Report and 5/28/24 Impact Analysis for NPRR1233. All Market Segments participated in the vote.
Summary of PRS Discussion	On 6/13/24, ERCOT Staff reviewed NPRR1233 and participants requested ERCOT share the aggregate inputs used to calculate the TSP fees. Discussion focused on the current methodology used to determine the weatherization fees and potential future modifications to the methodology with participants suggesting Resource Entity and TSP fees be separated to avoid subsidization and the average cost approach be applied to all those subject to inspections. On 7/18/24, participants reviewed the 5/28/24 Impact Analysis for NPRR1233.
TAC Decision	On 7/31/24, TAC voted unanimously to recommend approval of NPRR1233 as recommended by PRS in the 7/18/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 7/31/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)

Board Report

ERCOT Board Decision	On 8/20/24, the ERCOT Board voted unanimously to recommend approval of NPRR1233 as recommended by TAC in the 7/31/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1233 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM supports approval of NPRR1233.
ERCOT Opinion	ERCOT supports approval of NPRR1233.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1233 and believes it provides a positive market impact by adding a flat fee for inspection of federally owned generation units, which were otherwise reportedly precluded from paying their weatherization inspection invoices, and modifying the per-inspection fee for TSPs to align with the actual average cost incurred by ERCOT to perform a weatherization inspection.

Sponsor	
Name	David Kezell / Katherine Gross
E-mail Address	David.Kezell@ercot.com / Katherine.Gross@ercot.com
Company	ERCOT
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Cell Number	None
Market Segment	Not applicable

Market Rules Staff Contact	
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Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**

Board Report

None	

Market Rules Notes

Please note the following NPRRs also propose revisions to the ERCOT Fee Schedule:

- NPRR1202, Refundable Deposits for Large Load Interconnection Studies
- NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
- NPRR1242, Related to VCMRR042, SO2 and NOx Emission Index Prices Used in Verifiable Cost Calculations

Proposed Protocol Language Revision

ERCOT Fee Schedule

Effective December 20, 2023

Commented [EWG1]: Please note NPRRs 1202, 1234, and 1242 also propose revisions to this section.

The following is a schedule of ERCOT fees currently in effect. These fees are not refundable unless ERCOT Protocols provide otherwise.

Description	Nodal Protocol Reference	Calculation/Rate/Comment
Private Wide Area Network (WAN) fees	9.16.2	Actual costs of procuring, using, maintaining, and connecting to the third-party communications networks and related hardware that provide ERCOT WAN communications. The portion of costs for ERCOT's work regarding an initial installation or reconfiguration of an existing installation will not exceed $7,000. The portion of the monthly network management fee for ERCOT's work will not exceed $450 per month.
ERCOT Load Resource Registration and Generator Interconnection or Modification fees	NA	$500 for registration of a new Load Resource. If a Resource Entity seeks to increase the MW size of an existing Load Resource by more than 20% or change the Load Resource's registration between non-Controllable Load Resource and Controllable Load Resource, it will incur a registration fee of $500. The term "generator," as used in this fee schedule relating to interconnection fees and Full Interconnection Study (FIS) Application fees, includes Generation Resources, Energy Storage Resources (ESRs), and Settlement Only Generators (SOGs) but, as reflected below, Settlement Only Distribution Generators (SODGs) will incur a different fee amount than transmission connected SOGs. The following fee amounts apply for the registration of a new generator: $2,300 for SODGs;

		\$8,000 for generators that are less than 10 MW (other than SODGs); and \$14,000 for generators that are 10 MW or greater. If a Resource Entity for an existing SODG seeks to change its registration to a Distribution Generation Resource (DGR) it will incur a registration fee of \$8,000. If a Resource Entity seeks to make a modification that is covered by paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, to an existing generator it will incur a registration fee in association with the modification request. If, at the time the modification is submitted, the cumulative MW amount of the modification and any other modifications that have been submitted for that generator within the last 12 months amount to less than 10 MW, the registration fee will be \$2,300. If, at the time the modification is submitted, the cumulative MW amount of the modification and any other modifications that have been submitted for that generator within the last 12 months amount to 10 MW or greater, the registration fee will be \$14,000.
Full Interconnection Study (FIS) Application fee	NA	\$3,000 for an FIS Application relating to a new generator. \$2,700 for an FIS Application relating to modification of an existing generator.
Qualified Scheduling Entity (QSE) Application fee	9.16.2	\$500 per Entity
Subordinate QSE (Sub-QSE) Application fee	9.16.2	\$500 per Sub-QSE
Competitive Retailer (CR) Application fee	9.16.2	\$500 per Entity
Congestion Revenue Right (CRR) Account Holder Application fee	9.16.2	\$500 per Entity
Independent Market Information System Registered Entity (IMRE) fee	9.16.2	\$500 per Entity
Resource Entity Application fee	9.16.2	\$500 per Entity
Transmission and/or Distribution	9.16.2	\$500 per Entity

Service Providers (TDSPs)		
Counter-Party Background Check fee	9.16.2	$350 per Principal
Weatherization Inspection fees	NA	Resource Entities with Generation Resources or Energy Storage Resources (ESRs) and Transmission Service Providers (TSPs) shall pay fees to ERCOT for costs related to weatherization inspections conducted pursuant to 16 Texas Administrative Code (TAC) § 25.55, Weather Emergency Preparedness, as provided below. TSPs shall pay an inspection fee of $~~3,000~~4,500 for each of their substations or switching stations that are inspected. Each Resource Entity ~~with~~ to which this Section applies, other than those that own or control Generation Resources ~~or~~ and ESRs that are federally owned, shall pay an inspection fee calculated as the Semiannual Generation Resource Inspection Costs * (Resource Entity MW Capacity/Aggregate MW Capacity). ERCOT will perform this calculation twice per calendar year and gather the necessary MW capacity data for that six-month period on one of the last 15 Business Days at the end of the period. Terms used in this formula are defined as follows: Semiannual Generation Resource Inspection Costs for purposes of this Section equals ~~=~~ the sum of outside services costs, ERCOT internal costs, and overhead costs related to weatherization inspections, less inspection fees that will be invoiced to TSPs and Resource Entities with Generation Resources and ESRs that are federally owned, for that six-month period. Resource Entity MW Capacity for purposes of this ~~s~~Section equals ~~=~~ the total MW capacity (using real power rating) associated with a Resource Entity with Generation Resources or ESRs. ~~To calculate these amounts, ERCOT will query the Resource Integration and Ongoing Operations-Resource Services (“RIOO-RS”) for a report that lists the total MW capacity (real power rating) for all generation assets associated with each Resource Entity.~~ Aggregate MW Capacity for purposes of this Section equals ~~=~~ the total MW Capacity (using real power rating) of all the Resource ~~Entity~~ Entities, other than Generation Resources and ESRs that are federally owned ~~MW Capacity amounts~~. ~~To calculate this amount, ERCOT will query the RIOO-RS for a report that lists the total MW capacity (real power rating) for all Generation Resources and ESRs associated with all Resource Entities.~~ Resource Entities with Generation Resources and ESRs that are federally owned shall pay an inspection fee of $4,500 for each of the Resources that are inspected.

		ERCOT will issue Invoices semiannually in the months of January and July for the preceding six-month period to the Resource Entities and TSPs that owe inspection fees. Payment of the fee will be due within 30 days of the Invoice date and late payments will incur 18% annual interest. Entities that fail to pay their Invoice on time will be publicly reported in a filing with the Public Utility Commission of Texas (PUCT). Further payment terms and instructions will be included on the Invoice.
Voluminous Copy fee	NA	$0.15 per page in excess of 50 pages
Actual Costs associated with Information Requests	NA	ERCOT will provide an estimate to the requestor of any vendor or third-party costs ERCOT deems appropriate to fulfill the information request. If the requestor approves the cost estimate, the requestor must pay all such costs as instructed by ERCOT before the information will be delivered to the requestor.
ERCOT Labor Costs for Information Requests	NA	$15 per hour of ERCOT time. If ERCOT determines that a request will involve a substantial burden on ERCOT employee or contractor time to fulfill the request, ERCOT will provide an estimate to the requestor of the anticipated labor costs. If the requestor approves the cost estimate, the requestor must pay all such labor costs as instructed by ERCOT before the information will be delivered to the requestor.
ERCOT Training fees for courses that award Continuing Education Hours (CEHs)	NA	$25 per North American Electric Reliability Corporation (NERC) CEH. Examples of such trainings include, without limitation, the Operator Training Seminar and Black Start Training.
Cybersecurity Monitor fee for Non-ERCOT Utilities that participate in the Texas Cybersecurity Monitor Program	NA	The Cybersecurity Monitor fee amount varies from year to year. The current fee amount is posted on ERCOT's website here: https://www.ercot.com/services/programs/tcmp

ERCOT Impact Analysis Report

NPRR Number	1233	NPRR Title	Modification of Weather Inspection Fees on the ERCOT Fee Schedule
Impact Analysis Date	May 28, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) 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
None.

Board Report

NOGRR Number	245	NOGRR Title	Inverter-Based Resource (IBR) Ride-Through Requirements
Date of Decision	August 20, 2024		
Action	Recommended Approval		
Timeline	Urgent		
Estimated Impacts	Cost/Budgetary: Between $150k and $250k; Between $1.3M and $2.3M (Annual Recurring O&M); Between $0.5M and $0.8M (Short term contract labor O&M) Project Duration: 6 to 9 months		
Proposed Effective Date	First of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Priority – 2025; Rank – 3515 (for automation)		
Nodal Operating Guide Sections Requiring Revision	2.6.2, Generators and Energy Storage Resources 2.6.2.1, Frequency Ride-Through Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) 2.6.2.1, Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-Powered Generation Resources (WGRs) and Type 2 WGRs (new) 2.6.2.1.1, Temporary Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-Powered Generation Resources (WGRs) and Type 2 WGRs (new) 2.9, Voltage Ride-Through Requirements for Generation Resources and Energy Storage Resources 2.9.1, Voltage Ride-Through Requirements for Intermittent Renewable Resources Connected to the ERCOT Transmission Grid 2.9.1.1, Preferred Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs) (new) 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1		

	Wind-Powered Generation Resources (WGRs) and Type 2 WGRs (new) 2.11, Ride-Through Reporting Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-Powered Generation Resources (WGRs) and Type 2 WGRs (new) 2.11.1, Initial Frequency Ride-Through Capability Documentation and Reporting Requirements (new) 2.11.2, Initial Voltage Ride-Through Capability Documentation and Reporting Requirements (new) 2.12, Procedures for Frequency and Voltage Ride-Through Exemptions and Extensions for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-Powered Generation Resources (WGRs) and Type 2 WGRs (new) 2.12.1, Exemptions and Extensions Process (new) 2.12.1.1, Submission of Exemption Requests (new) 2.12.1.2, Submission of Extension Requests (new) 2.12.1.3, Timeline for Submission and Determination of Extension Requests (new) 2.13, Actions Following a Transmission-Connected Inverter-Based Resource (IBR), Type 1 Wind-Powered Generation Resource (WGR) or Type 2 WGR Apparent Failure to Ride-Through (new)
Related Documents Requiring Revision/Related Revision Requests	None
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) replaces the current voltage ride-through requirements for Intermittent Renewable Resources (IRRs) with voltage ride-through requirements for Inverter-Based Resources (IBRs) and Type 1 and Type 2 Wind-powered Generation Resources (WGRs) and provides new frequency ride-through requirements for IBRs and Type 1 and 2 WGRs consistent with or beyond requirements identified in the new 2800-2022 - Institute of Electrical and Electronics Engineers (IEEE) Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems ("IEEE 2800-2022 standard").
Reason for Revision	[X] Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience [ ] Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers

	☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	ERCOT submits this NOGRR based on reliability issues associated with the inability of some IBRs to ride-through system disturbances, and in light of the IEEE 2800-2022 standard. In its guidance document *Inverter-Based Resource Strategy*, the North American Reliability Corporation (NERC) noted it has supported the development of the IEEE 2800-2022 standard (and continues to support the IEEE P2800.2, Recommended Practice for Test and Verification Procedures for Inverter-based Resources (IBRs) Interconnecting with Bulk Power Systems, standards development efforts). Among other things, the document also highlights that: • New technology can introduce significant risks if not integrated properly which could result in high impact and high likelihood events that require substantive action; • Inverter and plant controls and protection systems must support the reliable operation of the bulk power system during system disturbances; • Disturbance reports, alerts, guidelines, and other deliverables have shown that abnormal IBR performance issues pose a significant risk to bulk power system reliability; • Analyzed events identified new performance issues such as momentary cessation, unwarranted inverter or plant-level tripping issues, controller interactions and instabilities, and other critical performance risks that must be mitigated; and • Generation ride-through and provision of essential reliability services is a core principle for reliable operation of the bulk power system. Consequently, this NOGRR proposes ride-through requirements for IBRs and Type 1 and Type 2 WGRs with specificity consistent with or beyond the IEEE 2800-2022 standard where appropriate (e.g.,

	applying to the Point of Interconnection Bus (POIB) instead of the "Resource Point of Applicability"). The revisions specify the ride-through requirements for IBRs rather than IRRs or Energy Storage Resources (ESRs) because some ESRs may not be IBRs and the IBR attributes create unique ride-through requirements. Additionally, due to Type 1 and 2 WGRs failing to ride through normal system disturbances, ERCOT proposes to apply several of the new requirements to these Resources. Some clarifications included from the IEEE 2800-2022 standard may not require additional "capability" but provide additional specificity for settings that can prevent failures rather than adjustments being made after a failure occurs. Failure of IBRs to ride-through normal frequency and voltage deviations on the ERCOT System can lead to severe consequences such as instability, cascading outages, or triggering an Under-Frequency Load Shed (UFLS) event which would result in the uncontrolled loss of firm Load. As such, this NOGRR does not propose to grandfather existing IBRs and Type 1 and Type 2 WGRs indefinitely. Rather, this NOGRR proposes that all IBRs and Type 1 and Type 2 WGRs with a Standard Generation Interconnection Agreement (SGIA) executed prior to August 1, 2024 ("existing IBRs"), maximize ride-through capability in an attempt to meet or exceed the new voltage ride-through requirements and the new frequency ride-through requirements as soon as practicable with all available software, firmware, settings and parameterization changes. IBRs and Type 1 and Type 2 WGRs that cannot meet the ride-through requirements will need to submit a request for an extension or a notice of intent to request an exemption by April 1, 2025 documenting such and provide a report to give ERCOT an accurate understanding of the physical limitations and maximum ride-through capability. During the implementation window or an approved extension, existing IBRs and Type 1/Type 2 WGRs will have to ensure they at least comply with the ride-through requirements in the Operating Guides in effect as of May 1, 2024 until they maximize their ride-through capability. An IBR or Type 1 WGR or Type 2 WGR that will be replaced or retrofitted and has documented technical exemptions granted, must upon replacement/retrofit meet the latest IEEE 2800 standard and preferred voltage ride-through requirements and will no longer be granted such exemptions. The proposed requirements will help improve several of the major failure modes identified in the Odessa disturbances in 2021 and 2022. Many of the Odessa related issues have been addressed with software and settings changes, which this NOGRR will require to be implemented. Market Participants in the Inverter Based Resource Task Force (IBRTF) encouraged ERCOT to focus on enhancements

	adopting portions of the IEEE 2800-2022 standard or NERC Reliability Guidelines that would provide the most reliability benefit in the short-term rather than a holistic approach. As such, additional requirements on IBRs may be necessary based on additional event analyses, lessons learned, recommendations contained in the NERC Odessa 2022 report, IEEE requirements, and NERC Reliability Standard revisions.
ROS Decision	On 2/8/23, ROS voted unanimously to table NOGRR245 and refer the issue to the Operations Working Group (OWG), Dynamics Working Group (DWG) and Inverter-Based Resource Task Force (IBRTF). All Market Segments participated in the vote. On 9/14/23, ROS voted to grant NOGRR245 Urgent status; to recommend approval of NOGRR245 as amended by the 9/13/23 NextEra comments as revised by ROS; and to forward to TAC NOGRR245 and the 1/11/23 Impact Analysis. There were 11 opposing votes from the Consumer (OPUC), Cooperative (3) (STEC, GVEC, LCRA), Independent Generator (Calpine), Independent Power Marketer (IPM) (NG Renewables), Independent Retail Electric Provider (IREP) (Reliant), Investor Owned Utility (IOU) (4) (Oncor, CNP, AEPSC, TNMP) Market Segments and two abstentions from the Consumer (Air Liquide) and IPM (SENA) Market Segments. All Market Segments participated in the vote.
Summary of ROS Discussion	On 2/8/23, ERCOT reviewed NOGRR245. Market Participants discussed whether it was appropriate to apply the new frequency ride-through requirements to certain existing IBRs, noting technical limitations of equipment and financial implications as concerns, and requested that ERCOT explore incorporating provisions that would allow for exemptions under some circumstances. ERCOT requested that Market Participants provide, for consideration, detailed information supporting their concerns, including specifics from original equipment manufacturers (“OEMs”) identifying technical limitations. On 9/14/23, ERCOT reviewed the 8/18/23 ERCOT comments, and responded to comments submitted by stakeholders and explained its reasoning for not supporting alternative frameworks. Participants debated the merits of the 8/18/23 ERCOT comments against the 9/13/23 NextEra comments and 9/5/23 Southern Power comments. Concerns expressed by certain participants on the 8/18/23 ERCOT comments focused on the technical feasibility of complying with the new requirements, timelines, associated costs, and commercial viability of Resources and future investment and the negative impact this may have on Resource adequacy in the ERCOT Region.

	Proponents of the 8/18/23 ERCOT comments highlighted reliability concerns and risk associated with IBRs and Type 1 and 2 WGRs inability to ride through system disturbances, and noted that the 9/13/23 NextEra comments and 9/5/23 Southern Power comments prioritize commercial needs over reliability.
TAC Decision	On 9/27/23, TAC voted unanimously to table NOGRR245. All Market Segments participated in the vote. On 3/27/24, TAC voted to recommend approval of NOGRR245 as recommended by ROS in the 9/14/23 ROS Report as amended by the 3/22/24 Joint Commenters 2 comments as revised by TAC. There were eight opposing votes from the Cooperative (4) (GSEC, LCRA, PEC, STEC) and IOU (4) (TNMP, CNP, Oncor, AEPSC) Market Segments and three abstentions from the Consumer (2) (OPUC, Residential Consumer) and Independent Generator (Calpine) Market Segments. All Market Segments participated in the vote. On 5/22/24, TAC voted unanimously to table NOGRR245. All Market Segments participated in the vote. On 6/7/24, TAC voted to recommend approval of NOGRR245 as recommended by TAC in the 3/27/24 TAC Report as amended by the 6/5/24 ERCOT comments as revised by TAC. There was one opposing vote from the IREP (Demand Control 2) Market Segment and ten abstentions from the Independent Generator (Luminant), IPM (2) (Morgan Stanley, SENA), IREP (3) (Reliant, Rhythm Ops, APG&E), and Municipal (4) (GP&L, DME, CPS Energy, Austin Energy) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 9/26/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR245. ERCOT addressed questions on the requests for information (RFIs) it will be issuing to Resource Entities and questions to OEMs regarding the feasibility of meeting the new ride-through requirements. Participants debated the appropriate path for NOGRR245; options discussed included remanding NOGRR245 to ROS for additional discussion, and bifurcating NOGRR245 to separately address requirements for existing and new IBRs. On 3/27/24, participants debated the merits of the 3/20/24 ERCOT comments versus the 3/22/24 Joint Commenters 2 comments. Proponents of the 3/20/24 ERCOT comments reiterated concerns that the 3/22/24 Joint Commenters 2 comments fall short of addressing the reliability risk associated with IBRs failing to ride

	through system disturbances and highlighted potential consequences including uncontrolled Outages up to potential system-wide Blackouts and increased costs to Customers. Proponents of the 3/22/24 Joint Commenters 2 comments expressed concern that the 3/20/24 ERCOT comments would negatively affect investor confidence in the ERCOT Region and emphasized that the 3/22/24 Joint Commenters 2 comments is a more balanced approach and promotes investor confidence while protecting reliability. To address certain participant concerns, edits were incorporated revising Section 2.14 in the 3/22/24 Joint Commenters 2 comments that would require ERCOT approval as a condition for allowing existing IBR, Type 1 and Type 2 WGR replacements and modifications that would reduce capability, or reductions in capability without a documented limited exemption to the applicable requirements. On 5/22/24, ERCOT reviewed its draft revisions to the proposed Operating Guide language in the 3/24/24 TAC Report. TAC discussed concepts and potential areas of agreement. On 6/7/24, TAC reviewed the 6/5/24 ERCOT comments and the 6/6/24 Joint Commenters 2 comments. Some participants and ERCOT expressed there was not sufficient time to thoroughly review the 6/6/24 Joint Commenters 2 comments noting the revisions significantly deviates from the redlines previously reviewed at the 5/31/24 TAC meeting and warned certain changes proposed by the Joint Commenters 2 would require analysis to understand the implications. The discussion highlighted areas of compromise in the 6/5/24 ERCOT comments and 6/6/24 Joint Commenters 2 comments, and areas of disagreement that largely focused on provisions related to physical/ hardware changes to equipment and the exemption process, including the conditions under which exemptions would be denied. ERCOT and certain participants expressed concern that the 6/6/24 Joint Commenters 2 comments fail to address the reliability risk, and the ERCOT Board and PUCT concerns. Edits to the 6/5/24 ERCOT comments incorporated language revisions reflected in the 6/6/24 Luminant comments, deferred the implementation of provisions related to physical/ hardware changes to 3/1/25 to provide additional time for continued discussions on these provisions in the stakeholder process, and a revision to paragraph (8) of Section 2.9.1 to replace a placeholder with “August 1, 2024”.
Explanation of Opposing TAC Votes	**Cooperative/GSEC** – The reason GSEC opposes NOGRR245 as recommended for approval by TAC in the 3/27/24 TAC Report is that ERCOT alone has the responsibility and is accountable for

	maintaining grid reliability. ERCOT's concerns must have priority over Market Participants' desires in these areas of disagreement. **Cooperative/LCRA** – LCRA could not, in good conscience, ignore the reliability risks communicated in the 3/20/24 ERCOT comments and 3/26/24 ERCOT comments on NOGRR245. We appreciate the extensive collaboration between ERCOT and the Joint Commenters 2 which involved concessions on both sides; however, ERCOT communicated it could go no further in negotiations without significant risks to reliability. Ultimately, our decision to support the version of NOGRR245 reflected in the 3/20/24 ERCOT comments was made with this thought in mind: LCRA desires to ensure the most reliable grid for the State of Texas while limiting the cost borne by our customers. LCRA did have concerns about backdating the effective date for new requirements. Investors in new projects make their decisions based on the rules of the game at the time. Changing those rules for in-flight projects can create regulatory uncertainty for future investment. In the 3/20/24 ERCOT comments, IBRs with an SGIA effective date of 6/1/2023 will fall under the new requirements and might potentially have to explore retrofitting an in-flight project. For justification, ERCOT states that moving the 6/1/2023 date any further out will cause at least 20-30 GW of projects to avoid the new requirements. However, ERCOT has created a path for these projects to be granted temporary exemptions out to 12/1/2028. We view this as a reasonable path to compliance while also ensuring system security. **Cooperative/PEC** – The opposing vote on NOGRR245 was due to ERCOT's strong concern that NOGRR245 as recommended for approval by TAC in the 3/27/24 TAC Report incorporates the 3/22/24 Joint Commenter's 2 revised proposal which does not meet reliability expectations, and could lead to major outages. **Cooperative/STEC** – STEC opposes NOGRR245 as recommended for approval by TAC in the 3/27/24 TAC Report because of the potentially significant and negative reliability risks that ERCOT has articulated, if implemented, would pose. **IOU/TNMP** – TNMP opposes NOGRR245 as recommended for approval by TAC in the 3/27/24 TAC Report because of the potentially significant and negative reliability risks that ERCOT has articulated, if implemented, would pose. **IOU/CNP** – CNP shares the same concern as others have expressed in the IOU Market Segment and opposes NOGRR245 as recommended for approval by TAC in the 3/27/24 TAC Report

	because of the potentially significant and negative reliability risks that ERCOT has articulated, if implemented, would pose. **IOU/Oncor** – Oncor opposes NOGRR245 as recommended for approval by TAC in the 3/27/24 TAC Report because of the potentially significant and negative reliability risks that ERCOT has articulated, if implemented, would pose. **IOU/AEPSC** – AEPSC opposes NOGRR245 as recommended for approval by TAC in the 3/27/24 TAC Report because of the potentially significant and negative reliability risks that ERCOT has articulated, if implemented, would pose. **IREP/ Demand Control 2** – Demand Control 2 opposed NOGRR245 recommend for approval by TAC in the 6/7/24 TAC Report because: (1) TAC members were not provided adequate time to give the 6/6/24 Joint Commenters 2 comments full consideration since the comments were not available until late evening on 6/6/24, and the 40 percent cost threshold proposed by ERCOT is arbitrary, extremely high and does not take into account the plant life of generating units or existing offtake contracts (i.e., either the threshold should be much lower or some aspect of commercial reasonableness added).
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 4/23/24, the ERCOT Board remanded NOGRR245 to TAC. There was one abstention. On 6/18/24, the ERCOT Board voted unanimously to table NOGRR245. On 8/20/24, the ERCOT Board voted unanimously to (1) recommended approval of NOGRR245 as recommended by TAC in the 6/7/24 TAC Report as amended by the 8/16/24 ERCOT comments with a recommended priority of 2025 and rank of 3515, and (2) designate a subsequent NOGRR as a Board Priority Revision Request to address the remaining details of the exemption process and to have the NOGRR at the ERCOT Board's February 2025 meetings for consideration, with instruction to TAC leadership

	to provide detailed reports on this subsequent NOGRR at the ERCOT Board's October and December 2024 meetings.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR245.
ERCOT Opinion	ERCOT supports approval of NOGRR245.
ERCOT Market Impact Statement	ERCOT has reviewed NOGRR245 as recommended for approval by the ERCOT Board in the 8/20/24 Board Report and believes the rate and severity of ride-through failures will be reduced as Resource Entities maximize their ride-through capability and implement the modified performance failure mitigation process. This version of NOGRR245 is a reasonable compromise that is responsive to most stakeholder concerns. Customers will likely continue to face exposure to the current high risk of instability and uncontrolled Outages until improvements are implemented by the Resource Entities of IBRs and Type 1 and Type 2 WGRs. As improved models are submitted as part of maximization efforts, ERCOT may discover reliability issues that had not been previously identified. Managing these reliability issues may lead to transmission congestion or additional transmission project needs.

Sponsor	
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Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
Brazos Electric 021623	Provided summary of impacts NOGRR245 would have on Brazos Electric
GE Renewable Energy 021723	Sought clarification on active and reactive response requirements during ride through events and the definition and requirement for phase angle jump, and specify IBR plants are not expected to ride through radial opening and reclosing of tie lines
Oncor 030723	Proposed revisions to clarify the interconnecting Transmission Service Provider's (TSP's) role in event analysis
Advanced Power Alliance 032023	Proposed revisions reinstating voltage ride-through exemptions removed in the NOGRR245 as submitted, and established temporary and permanent good cause exemptions for Resource owners
ERCOT 040523	Revised language to address stakeholder comments related to settings and adjusted timelines
RWE 042623	Argued NOGRR245 should be severed to allow rapid adoption of the proposed voltage and frequency ride-through components for new Resources and a new separate NOGRR be developed to address older operational Generation Resources
Invenergy 050123	Suggested all Resources with an SGIA dated before January 1, 2023 be exempted from the new requirements, a good cause exception process be created for extenuating circumstances, and a staged implementation process for new standards to allow OEMs time to comply
Southern Power 050123	Highlighted technical concerns for certain existing IBRs and proposed an exemption process to account for existing IBRs' limitations
EDFR 050223	Requested the new requirements apply to projects with an SGIA executed after the effective date of NOGRR245, and for legacy projects adopt a phased-in approach to comply with the new standards
GE Renewable Energy 050323	Listed the challenges related to the implementation of the proposed requirements for the GE fleet in ERCOT
Advanced Power Alliance 050323	Recommended ERCOT continue to work with IBRs and manufacturers to identify a set of requirements for new Resources and a separate set of requirements may be developed for existing Resources after a technical feasibility review is completed
Clearway Renew 050323	Recommended ERCOT separate NOGRR245 into two NOGRRs - one set of requirements for new Resources with SGIAs signed after the effective date of NOGRR245, and a separate set of requirements for existing Resources

Pattern Energy 050323	Requested NOGRR245 remain tabled to provide time for further analysis by the OEMs
TSPA 051723	Submitted concepts for an alternative framework that would extend the compliance date and adopt a phased-in approach to implementation of the new ride-through requirements
Siemen Gamesa Renewable Energy 060623	Indicated it does not support applying the new performance standards to existing wind turbines
Avangrid Renewables 060723	Requested ERCOT undertake a study to determine the amount of capacity at risk of becoming unavailable under NOGRR245; and supported a bifurcated approach for implementation for existing and new IBRs and recommended ERCOT explore alternative methods for strengthening the transmission grid
AES CE 061623	Recommended NOGRR245 be applied only to new generation with a SGIA executed on or after the effective date of NOGRR245, and supported that ERCOT divide NOGRR245 into two NOGRRs for legacy and new projects
ERCOT 062223	Modified the 4/5/23 ERCOT comments to include revised compliance dates and requirements
Vestas 062223	Encouraged ERCOT to reassess the retroactive application of new requirements on certain existing Resources; and expressed compliance concerns
Engie 072623	Recommended ERCOT to continue to work OEMs to work on an agreeable and feasible timeline for implementation
NextEra 072823	Requested NOGRR245 remain tabled at ROS, and noted specific concerns were not addressed by 6/22/23 ERCOT comments, and expressed additional concerns regarding implementation timelines and compliance
Advanced Power Alliance 072823	Recommended ERCOT continue working with IBRs and OEMs to identify a set of requirements based on timelines that can be met, and suggested the Impact Analysis needs to be corrected to reflect the changes to grid operations and practices that will be necessary when NOGRR245 is adopted
Sierra Club 073123	Agreed with the 7/26/23 Engie comments and suggested meetings continue to be held to continue discussion regarding timelines for implementation
TAEBA 073123	Recommended NOGRR245 remain tabled and that ERCOT revise the 6/22/23 ERCOT comments and develop deadlines with stakeholders to ensure the timeline to comply with the IEEE 2800 - 2022 standard is practically achievable
GE Vernova 073123	Expressed concern that the timelines proposed in NOGRR245 are too aggressive and outlined expected timelines associated with new installations and legacy units

Invenergy 073123	Discussed the feasibility of retrofitting older IBRs to meet the new requirements, expressed concern that the retroactive application of NOGRR245 will have a negative impact on Resource adequacy in the ERCOT Region, argued NOGRR245 should not retroactively apply to existing IBRs, NOGRR245 should be bifurcated to address new and existing IBR requirements separately, and the new specific requirements for existing projects should be eliminated
TSPA 080223	Encouraged ERCOT to continue discussions with OEMs and Resource owners to identify workable solutions and appropriate timelines and to explore the implementation of other technologies and transmission solutions, and recommended incorporating a good cause exception process
RWE 080223	Commented that any proposed standard needs to be strictly forward looking with an adequate lead time for the industry as a whole and outlined reasoning for not supporting the retroactive application of the standards on older operational IBRs
Orsted 080323	Recommended ERCOT establish a good cause exemption provision for IBRs that demonstrate they cannot practically comply with the IEEE 2800-2022 standard, and emphasized the importance of proper test guidelines and NOGRR245 accounting for the time needed to develop testing standards
Advanced Power Alliance 081123	Requested ERCOT revise the 6/22/23 ERCOT comments by August 31, 2023 to provide stakeholders adequate time ahead of the September 7th ROS meeting to review the proposal and respond with comments
ERCOT 081823	Incorporated Type 1 and Type 2 WGRs into the 6/22/23 ERCOT comments
Invenergy 090423	Expressed concern that the 8/18/23 ERCOT comments do not fully address the OEM and Market Participant concerns about technical and timing feasibility, cost, and overall impact the proposal would have on system reliability
Southern Power 090523	Proposed revisions to the 8/18/23 ERCOT comments to consider capabilities and limitations of existing Resources
GE Vernova 090523	Suggested modifying the ERCOT proposal to incorporate an additional qualifier regarding the disabling of features and replace references to “zone” with “range”
NextEra 090523	Provided alternative language that would require IBRs to comply with ERCOT's new reliability requirements if it is commercially reasonable to do so, and provided a new compliance framework
ERCOT 090623	Highlighted ERCOT’s reliability concerns expressed in various stakeholder forums over the past several months regarding the inability of IBRs and Type 1 and Type 2 WGRs to ride-through system disturbance