|  |  |  |  |
| --- | --- | --- | --- |
| **NPRR Number** | [**1211**](https://www.ercot.com/mktrules/issues/NPRR1211) | **NPRR Title** | **Move OBD to Section 22 – Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints** |
| **Date of Decision** | January 24, 2024 |
| **Action** | Recommended Approval |
| **Timeline**  | Normal |
| **Estimated Impacts** | Cost/Budgetary: Less than $5k (Operations & Maintenance (O&M))Project Duration: Not applicable |
| **Proposed Effective Date** | Upon system implementation |
| **Priority and Rank Assigned** | Not applicable |
| **Nodal Protocol Sections Requiring Revision**  | 4.5.1, DAM Clearing Process6.4.9.2.2, SASM Clearing Process6.5.7.1.11, Transmission Network and Power Balance Constraint ManagementSection 22, Attachment Q, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (new) |
| **Related Documents Requiring Revision/Related Revision Requests** | Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (Upon approval of this NPRR, this will be removed from the Other Binding Documents List.) |
| **Revision Description** | This Nodal Protocol Revision Request (NPRR) incorporates the Other Binding Document “Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints” into the Protocols. |
| **Reason for Revision** |  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 1 – Be an industry leader for grid reliability and resilience [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) 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](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) 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 and/or 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** | This NPRR is published for transparency and to standardize the approval process for all binding language.  |
| **PRS Decision** | On 12/15/23, PRS voted unanimously to recommend approval of NPRR1211 as submitted. All Market Segments participated in the vote.On 1/11/24, PRS voted unanimously to endorse and forward to TAC the 12/15/23 PRS Report and 11/20/23 Impact Analysis for NPRR1211. All Market Segments participated in the vote. |
| **Summary of PRS Discussion** | On 12/15/23, there was no discussion.On 1/11/24, participants reviewed the 11/20/23 Impact Analysis. |
| **TAC Decision** | On 1/24/24, TAC voted unanimously to recommend approval of NPRR1211 as recommended by PRS in the 1/11/24 PRS Report. All Market Segments participated in the vote. |
| **Summary of TAC Discussion** | On 1/24/24, 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 Comments were reviewed and discussed (if applicable) Other: (explain) |

|  |
| --- |
| **Opinions** |
| **Credit Review** | ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1211 and do not believe that it requires changes to credit monitoring activity or the calculation of liability. |
| **Independent Market Monitor Opinion** | The Independent Market Monitor (IMM) has no opinion on NPRR1211. |
| **ERCOT Opinion** | ERCOT supports approval of NPRR1211. |
| **ERCOT Market Impact Statement** | ERCOT Staff has reviewed NPRR1211 and believes it has a positive market impact by standardizing the approval process for binding language. |

|  |
| --- |
| **Sponsor** |
| **Name** | Ann Boren |
| **E-mail Address** | Ann.Boren@ercot.com  |
| **Company** | ERCOT |
| **Phone Number** | 512-248-6465 |
| **Cell Number** |  |
| **Market Segment** | Not Applicable |

|  |
| --- |
| **Market Rules Staff Contact** |
| **Name** | Brittney Albracht |
| **E-Mail Address** | Brittney.Albracht@ercot.com  |
| **Phone Number** | 512-225-7027 |

|  |
| --- |
| **Comments Received** |
| **Comment Author** | **Comment Summary** |
| None |  |

|  |
| --- |
| **Market Rules Notes** |

To improve transparency, existing Other Binding Document language for new Section 22, Attachment Q, is represented as blackline, with only proposed changes marked as redline.

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

* NPRR1186, Improvements Prior to the RTC+B Project for Better ESR State of Charge Awareness, Accounting, and Monitoring
	+ Section 4.5.1
	+ Section 6.4.9.2.2
* NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
	+ Section 4.5.1

|  |
| --- |
| **Proposed Protocol Language Revision** |

4.5.1 DAM Clearing Process

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(iii) Other constraints –

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

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

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

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

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

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

|  |
| --- |
| ***[NPRR1008 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014:]***(4) The DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues, including revenues based on Ancillary Service Demand Curves (ASDCs), minus the offer-based costs over the Operating Day, subject to security and other constraints. (a) The bid-based revenues include revenues from ASDCs, DAM Energy Bids, bid portions of Energy Bid/Offer Curves, and Point-to-Point (PTP) Obligation bids. (b) The offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of any Resource that submitted a Three-Part Supply Offer, DAM Energy-Only Offers, offer portions of Energy Bid/Offer Curves, Ancillary Service Only Offers, and Ancillary Service Offers. (c) Security constraints specified to prevent DAM solutions that would overload the elements of the ERCOT Transmission Grid include the following: (i) Transmission constraints – transfer limits on energy flows through the ERCOT Transmission Grid, e.g., thermal or stability limits. These limits must be satisfied by the intact network and for certain specified contingencies. These constraints may represent:(A) Thermal constraints – protect Transmission Facilities against thermal overload.(B) Generic constraints – protect the ERCOT Transmission Grid against transient instability, dynamic stability or voltage collapse.(C) Power flow constraints – the energy balance at required Electrical Buses in the ERCOT Transmission Grid must be maintained. (ii) Resource constraints – the physical and security limits on Resources that submit Three-Part Supply Offers or Energy Bid/Offer Curves:(A) Resource output constraints – the Low Sustained Limit (LSL) and High Sustained Limit (HSL) of each Resource; and (B) Resource operational constraints – includes minimum run time, minimum down time, and configuration constraints.(iii) Other constraints – (A) Linked offers – the DAM may not select any one part of that Resource capacity to provide more than one Ancillary Service or to provide both energy and an Ancillary Service in the same Operating Hour. The DAM may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service or energy in the same Operating Hour, provided that linked Energy and Off-Line Non-Spinning Reserve (Non-Spin) Resource-Specific Ancillary Service Offers are not awarded in the same Operating Hour.(B) The sum of the awarded Resource-Specific Ancillary Service Offer capacities for each Resource must be within the Resource limits specified in the Current Operating Plan (COP) and Section 3.18, Resource Limits in Providing Ancillary Service, and the Resource Parameters as described in Section 3.7, Resource Parameters.(C) Block Resource-Specific Ancillary Service Offers for a Load Resource – blocks will not be cleared unless the entire quantity block can be awarded. Because block Resource-Specific Ancillary Service Offers cannot set the Market Clearing Price for Capacity (MCPC), a block Ancillary Service Offer may clear below the Ancillary Service Offer price for that block.(D) Block DAM Energy Bids, DAM Energy-Only Offers, and PTP Obligation bids – blocks will not be cleared unless the entire time and/or quantity block can be awarded. Because quantity block bids and offers cannot set the Settlement Point Price, a quantity block bid or offer may clear in a manner inconsistent with the bid or offer price for that block.(E) Combined Cycle Generation Resources – The DAM may commit a Combined Cycle Generation Resource in a time period that includes the last hour of the Operating Day only if that Combined Cycle Generation Resource can transition to a shutdown condition in the DAM Operating Day.(F) Energy Storage Resources (ESRs) – The energy cleared for an ESR may be negative, indicating purchase of energy, or positive, indicating sale of energy. (d) Ancillary Service needs will be reflected in ASDCs for each Ancillary Service. Self-Arranged Ancillary Service Quantities will first be used to meet the ASDCs, and the remaining Ancillary Service needs are met from Ancillary Service Offers, as long as the costs do not exceed the ASDC value. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service. |

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

|  |
| --- |
| ***[NPRR1004: Replace paragraph (5) above with the following upon system implementation:]***(5) ERCOT shall determine the appropriate Load distribution factors to allocate offers, bids, and source and sink of PTP Obligations at a Load Zone across the energized power flow buses that are modeled with Load in that Load Zone. ERCOT shall derive DAM Load distribution factors with the set of Load distribution factors constructed in accordance with the ERCOT Load distribution factor methodology specified in paragraph (c) of Section 3.12, Load Forecasting. In the event the Load distribution factors are not available, the Load distribution factors for the most recent preceding Operating Day will be used. |

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

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

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

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

(b) Use the following rules in order:

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

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

(iii) Use System Lambda.

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

(10) Day-Ahead MCPCs shall not exceed the System-Wide Offer Cap (SWCAP). Ancillary Service Offers higher than corresponding Ancillary Service penalty factors, as defined in Appendix 2, Day-Ahead Market Optimization Control Parameters, of Section 22, Attachment Q, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints, will not be awarded.

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

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

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

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

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

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

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

6.4.9.2.2 SASM Clearing Process

(1) SASM procurement requirements are:

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

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

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

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

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

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

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

(e) SASM MCPCs for any Ancillary Service shall not exceed the SWCAP. Ancillary Service Offers higher than corresponding Ancillary Service penalty factors, as defined in Appendix 2, Day-Ahead Market Optimization Control Parameters, of the Section 22, Attachment Q, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints, will not be awarded.

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

6.5.7.1.11 Transmission Network and Power Balance Constraint Management

(1) ERCOT may not allow any constraint (contingency and limiting Transmission Element pair) identified by NSA to be activated in SCED until it has verified that the contingency definition in NSA associated with the constraint is accurate and appropriate given the current operating state of the ERCOT Transmission Grid. ERCOT shall continuously post to the MIS Secure Area all constraint contingencies in the NSA. ERCOT shall provide relevant constraint information, including, but not limited to, the contingency name as provided in the standard contingency list, whether or not the constraint is active in SCED, the overloaded Transmission Element name, the Rating of the overloaded Transmission Element including Generic Transmission Limits (GTLs) expressed in MW and MVA, and pre-contingency or post-contingency flows expressed in MW and MVA. For each Operating Day, ERCOT shall post to the MIS Secure Area within five days, a report listing all constraints with pre-contingency or post-contingency flows which exceeded the Rating of the overloaded Transmission Element for at least 15 minutes consecutively that were not activated in SCED and an explanation of why each constraint was not activated.

(2) Pursuant to Section 22, Attachment Q, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints, ERCOT shall establish a maximum Shadow Price for each network constraint as part of the definition of contingencies. The cost calculated by SCED to resolve an additional MW of congestion on the network constraint is limited to the maximum Shadow Price for the network constraint.

(3) Pursuant to Section 22, Attachment Q, ERCOT shall establish a maximum Shadow Price for the power balance constraint. 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.

(4) If ERCOT determines that rating(s) in the Network Operations Model or configuration of the Transmission Facilities are not correct, then the TSP will provide the appropriate data submittals to ERCOT to correct the problem upon notification by ERCOT.

|  |
| --- |
| [NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:](4) If ERCOT determines that rating(s) in the Network Operations Model or configuration of the Transmission Facilities are not correct, then the TSP or DCTO will provide the appropriate data submittals to ERCOT to correct the problem upon notification by ERCOT. |

ERCOT Nodal Protocols

Section 22

**Attachment Q:** **Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints**

Date TBD

|  |  |  |  |
| --- | --- | --- | --- |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |
|  |  |  |  |

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |

# 1. Purpose

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 in the cases of constraint violations.

This Business Practice 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:

 

Where:

 is LMP at Electrical Bus *EB*

 is system lambda (Shadow Price of power balance)

 is Shift Factor for Electrical Bus *EB* for transmission *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:



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:

.

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



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 
	+ LMP congestion component 
	+ Unit power output adjustment .

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:

.

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  directly limits the transmission congestion costs:

 .

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

.

The maximal unit power output adjustment  will be determined by condition:

 

3.3 Shift Factor Cutoff

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

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

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

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

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

3.4 Methodology Outline

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

(a) Determine Shift Factor efficiency threshold  (default x%)

(b) Determine maximal LMP congestion component  (default $y/MWh)

(c) Calculate maximal Shadow Price for transmission constraints:

 

(d) Determine Shift Factor cutoff threshold  (default z%)

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

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

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

**Generic Transmission Constraint Shadow Price Caps in SCED**

* 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]](#footnote-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.

**Figure 2**

Figures 1 and 2 show that:

* For a constraint shadow price cap of $5,251/MW
	+ Marginal units with an o*ffer 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 system-wide offer cap in some circumstances**. This is most likely to occur when there are one or more irresolvable constraints on the system *and* when overall dispatchable supply on the system is tight. Relatively speaking, it is more likely that individual node prices will exceed the system-wide offer cap than hubs or load zones, but it is possible that hub or load zone prices could exceed the system-wide offer cap. It is not possible in the nodal system to assign constraint shadow price caps and power balance penalty factor values that achieve the desired reliability and efficiency objectives and ensure that all LMPs remain within the bounds of the system-wide offer caps under all circumstances.

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

* Formulating a mitigation plan which may include
* Transmission reconfiguration (switching)
* Load rollover to adjacent feeders
* Load shed plans
* Redistribution of ancillary services to increase the capacity available within a particular area.
* Commitment of additional units.
* Re-dispatching generation through over-riding High Dispatch Limit (HDL) and Low Dispatch Limit (LDL) in accordance with paragraph (3)(g) of Protocol Section 6.5.7.1.10.

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

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

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

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

1. 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
2. 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:

1. 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,
2. The Generation Resource with the highest absolute value of the negative shift factor on the violated constraint (this resource is referred to as Generation Resource D in the designation of the net margin Settlement Point Price (SPP) described below).

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

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

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

The Shadow Price Cap on the constraint that has met the trigger conditions described in Section 3.6.1, will be set to the minimum of E or F as follows:

1. 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
2. The Maximum of the either the largest value of the Mitigated Offer Cap for Generation Resource C, as determined above, divided by the absolute value of its shift factor impact on the constraint or$2000 per MW.

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

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

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

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

1. As soon as practicable, but not more than ten (10) business days after the triggers are met, review transmission outages and recall outages that are contributing to overloading the constraint(s), if feasible.

2. As soon as practicable, but not more than thirty (30) days after the triggers are met, review and develop Remedial Action Plans (RAP) or Temporary Outage Action Plans (TOAP) to mitigate congestion on the affected constraint(s), if feasible. To the degree that a RAP or TOAP can be developed, ERCOT shall implement it through an Emergency Database Load, if necessary to avoid delay in addressing the congestion.

3. As soon as practicable, but not more than ninety (90) days after the triggers are met, review and develop or identify one or more Special Protection Systems or transmission proposal(s) to alleviate the risk of future congestion on the affected constraint(s), if feasible, so long as the proposed solution produces an overall reduction of congestion on the ERCOT system.

4. Perform a detailed review of the constraint(s) that is irresolvable by SCED, and in the next annual Regional Transmission Plan, identify projects that will mitigate the risk of future recurrence of the condition, if any.

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

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

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

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

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

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

# 4. Power Balance Shadow Price Cap

4.1 The Power Balance Penalty

The Power Balance constraint is the balance between the ERCOT System Load and the amount of generation that is dispatched by SCED to meet that load. This Shadow Price for this constraint, also called System Lambda (λ), is the cost of providing one MWh of energy at the reference Electrical Bus. System Lambda, i.e. the Shadow Price for the Power Balance constraint, is equal to the change in the SCED objective function obtained by relaxing the Power Balance constraint by 1MW. The System Lambda is the energy component of Locational Marginal Price at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this Shadow Price, i.e. Power Balance Penalty is the maximum cost paid for one addition/less MW of generation to meet the ERCOT system load constraint. This section describes those factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MW versus the amount of the mismatch and provides the resulting Power Balance Penalty Curve proposed for 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 Locational Marginal Price at each Settlement Point in ERCOT. The Power Balance Penalty sets the maximum limit for this Shadow Price, i.e. Power Balance Penalty is the maximum cost paid for one addition/less MW of generation to meet the ERCOT system load constraint. This section describes those factors that ERCOT considered in developing the amount of the Power Balance Penalty in $/MW versus the amount of the mismatch and provides the resulting Power Balance Penalty Price proposed for 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 System Wide Offer Cap (SWCAP),
* The expected percentage of intervals with SCED Up Ramp scarcity,
* The expected extent of Ancillary Service deployment by operators during intervals with capacity scarcity, and
* The transmission constraint penalty values.

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

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

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

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

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

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

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

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

4.3 The ERCOT Power Balance Penalty Curve

Based on the criteria described in Section 4.2, Factors Considered in the Development of the Power Balance Penalty Curve, above, the SCED under-generation Power Balance Penalty is shown in 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 ≤ limit

* Dispatch Limits

 LDL ≤ Base Point ≤ HDL

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



Where

 = System Lambda or Power Balance Penalty (if a Power Balance violation exists) at time interval “t”

 = Shift Factor impact of the bus “bus” on constraint “c” at time interval “t”

 = Shadow Price of constraint “c” at time interval “t” (capped at Max Shadow Price for this constraint).

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

* 1. Cost of moving up the Resource = Shift Factor \* Transmission Constraint Penalty + Offer cost
	2. Cost of moving down the Resource = Power Balance Penalty

The Resource will be moved down for resolving constraints if (a) > (b).

If (a) < (b) then the Resource will be moved up for meeting Power Balance.

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

# Appendix 2: Day-Ahead Market Optimization Control Parameters

The purpose of the Day-Ahead Market (DAM) is to economically co-optimize energy and Ancillary Service by simultaneously clearing offers and bids submitted by the Market Participants to maximize social welfare while observing the transmission and generation physical constraints. The ERCOT DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to transmission security and other constraints as described in Protocol Section 4, Day-Ahead Operations. The bid‑based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation Bids. The Offer‑based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of Resources that submitted a Three-Part Supply Offer, as well as the DAM Energy-Only Offers, 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 Protocol Section 4.5.1, DAM Clearing Process, the transmission constraint limits needs to be satisfied in DAM and hence the transmission constraint penalty values are set to very high values to ensure that the constraints are not violated in DAM.

|  |
| --- |
| ***[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***The purpose of the Day-Ahead Market (DAM) is to economically co-optimize energy and Ancillary Service by simultaneously clearing offers and bids submitted by the Market Participants to maximize social welfare while observing the transmission and generation physical constraints. The ERCOT DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to transmission security and other constraints as described in Protocol Section 4, Day-Ahead Operations. The bid‑based revenues include revenues from DAM Energy Bids and Point-to-Point (PTP) Obligation Bids. The Offer‑based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of Resources that submitted a Three-Part Supply Offer, as well as the DAM Energy-Only Offers, 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 - 1

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

 |

**2.1 Over/Under – Generation Penalty Factors**

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

 **2.2 Ancillary Service Penalty Factors**

The Ancillary Service penalty factors serve two purposes. The procured amount of an Ancillary Service can be lower than the difference between the amount of the required AS, as specified in the AS Plan, and the amount of the self-arranged AS. The value of the AS penalty factors are chosen to allow the selection of AS offers that result in the least amount of deficit considering the maximum AS penalty factors referenced in Appendix 2, Table 2-1 for each given AS over the Operating Day and to assign a priority to the AS constraints relative to the enforcement of the Power Balance and Network Transmission constraints. Additionally, the increasing penalty cost structure from Non-Spin AS to Regulation AS prioritizes the DAM AS procurement as first Regulation Services, then Responsive Reserve (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 AS penalty factors are not used to set the Market Clearing Price for Capacity (MCPC) for each Ancillary Service. Instead, the infeasible AS requirement amounts are reduced to the feasible level and the DAM clearing is rerun so that the price of the last AS awarded MW sets the MCPC for each Ancillary Service. The AS penalty factors used in DAM are also used in the Supplemental Ancillary Service Market (SASM) engine.

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

**2.3 Network Transmission Penalty Factors**

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

Finally, the Non-Thermal (generic constraint) Penalty Factor assigns these constraints the same priority level in the optimization as the 345 kV security constraints making both less than the 345 kV base case constraints.

|  |
| --- |
| ***[OBDRR020: Replace the paragraph above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]***The DAM Clearing Engine includes the Network Security Monitor (NSM) application and Network Constrained Unit Commitment (NCUC) application. These applications execute in a loop beginning with a NSM execution followed by a NCUC execution until a secure commitment pattern that maximizes the objective function is achieved (i.e. NSM begins with an estimated initial unit commitment and uses, thereafter, the latest NCUC commitment). The value of the Network Transmission Penalty Factors for each specified voltage level are used in NCUC application to set the rank order for relaxing the base case constraints and the security constrained network transmission constraints by voltage level and to set the rank order for the enforcement of the Network Transmission Constraints relative to the Power Balance constraint. The increasing value of the Network Transmission Penalty Factors for increasing voltage levels assures that base case and security constraint violations are relaxed progressively in the NSM and NCUC applications in order of voltage level, from lowest to highest. This assures that the DAM solution will honor network transmission constraints in the rank order from the 345 kV to the 69 kV voltage level. Additionally, these penalty factors are chosen such that, in each voltage range, the base case violations have a slightly higher penalty factor than the security constrained penalty factors. This assigns a higher priority in the NSM and NCUC to a network transmission base case violation compared to a network transmission security constrained violation. In other words, within the same voltage level, the security constraints are relaxed before the base case constraints. Finally, the Non-Thermal (generic constraint) Penalty Factor assigns these constraints the same priority level in the optimization as the 345 kV security constraints making both less than the 345 kV base case constraints. |

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

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. [↑](#footnote-ref-1)