$RTMCPCRUS_{y}$	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up per SCED interval* - The Real-Time MCPC for Reg-Up for the SCED interval *y*.
$PCRUR_{r, q, DAM}$	MW	*Procured Capacity for Reg-Up per Resource per QSE in DAM*—The Reg-Up capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
$DASARUQ_{q}$	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
$RUTP_{q}$	MW	*Trade Purchases for Reg-Up for the QSE*— The final approved trade purchases for QSE *q* for Reg-Up for the Operating Hour.
$RUTS_{q}$	MW	*Trade Sales for Reg-Up for the QSE*— The final approved trade sales for QSE *q* for Reg-Up for the Operating Hour.
$TLMP_{y}$	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval *y* within the Settlement Interval.
$RURWF_{y, r, \cancel{p}}$	none	*Reg-Up Resource Node Weighting Factor per interval* - The Reg-Up Resource weight, based on Reg-Up awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
~~*p*~~	~~none~~	~~A Resource Node Settlement Point.~~

(2) Reg-Up Only Charge:

$$\mathbf{RTRUOAMT_{q} = (1/4) * DARUOAWD_{q} * RTMCPCRU}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTRUOAMT_{q}$	$	*Real-Time Reg-Up Only Amount for the QSE*—The total charge to QSE *q* in Real-Time for Reg-Up Only awards for each 15-minute Settlement Interval.
$DARUOAWD_{q}$	MW	*Day-Ahead Reg-Up Only Award for the QSE*—The Reg-Up only capacity awarded in the DAM to the QSE *q* for the Operating Hour.
RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.

q	none	A QSE.

(3) Reg-Up Trade Overage Charges:

RTRUTOAMT $_q$ = (1/4) * RTRUTO $_q$ * RTMCPCRU

The above variables are defined as follows:

Variable	Unit	Description
RTRUTOAMT $_q$	$	*Real-Time Reg-Up Trade Overage Amount for the QSE*— The total charge to QSE q in Real-Time for Reg-Up trade overages for each 15-minute Settlement Interval.
RTRUTO $_q$	MW	*Real-Time Reg-Up Trade Overage for the QSE* — The quantity of submitted Reg-Up trades in excess of DAM self-arrangement quantities for the QSE q for the Operating Hour.
RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.3 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.3 Regulation Down Service Payments and Charges

(1) Reg-Down Imbalance Payment or Charge:

$$\mathbf{RTRDIMBAMT}_{q} = (-1) * [\sum_{r} [\mathbf{RTRDREV}_{q,r} - (1/4) * (\mathbf{PCRDR}_{r,q,DAM} * \mathbf{RTMCPCRD})] - (1/4) * (\mathbf{DASARDQ}_{q} * \mathbf{RTMCPCRD}) + (1/4) * (\mathbf{RDTP}_{q} - \mathbf{RDTS}_{q}) * \mathbf{RTMCPCRD}]$$

Where:

$$\mathbf{RTRDREV}_{q,r} = (1/4) * \mathbf{RTRDAWD}_{q,r} * \mathbf{RTMCPCRDR}_{q,r}$$

$$\mathbf{RTMCPCRDR}_{q,r} = \sum_{y} (\mathbf{RDRWF}_{q,r,\cancel{p},y} * (\mathbf{RTMCPCRDS}_{y} + \mathbf{RTRDPARDS}_{y}))$$

$$\mathbf{RTRDAWD}_{q,r} = \sum_{y} (\mathbf{RNWF}_{y} * \mathbf{RTRDAWDS}_{q,r,\cancel{p},y})$$

Where:

$$\text{RDRWF}_{q,r,\cancel{p},y} = [\max(0.001, \text{RTRDAWDS}_{q,r,\cancel{p},y}) * \text{TLMP}_{y}] / [\sum_{y} \max(0.001,$$

$$\text{RTRDAWDS}_{q,\,r,\,\cancel{p},\,y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDIMBAMT $_{q}$	$	*Real-Time Reg-Down Imbalance Amount for the QSE*—The total payment or charge to QSE *q* for the Real-Time Reg-Down imbalance for each 15-minute Settlement Interval.
RTRDAWD $_{q, r}$	MW	*Real-Time Reg-Down Award per Resource per QSE* - The Reg-Down amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRDREV $_{q, r}$	$	*Real-Time Reg-Down Revenue*—The Real-Time Reg-Down revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRDAWDS $_{q, r, \cancel{p}, y}$	MW	*Real-Time Reg-Down Award per Resource per QSE per SCED interval* - The Reg-Down Amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCRDR $_{q, r}$	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down per Resource per QSE*—The Real-Time MCPC for Reg-Down for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMCPCRDS $_{y}$	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down per SCED interval* - The Real-Time MCPC for Reg-Down for the SCED interval *y*.
PCRDR $_{r, q, DAM}$	MW	*Procured Capacity for Reg-Down per Resource per QSE in DAM*—The Reg-Down capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCRD	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
RTRDPARDS $_{y}$	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Reg-Down per SCED interval* - The Real-Time price adder for Reg-Down that captures the impact of reliability deployments on Reg-Down prices for the SCED interval *y*.
DASARDQ $_{q}$	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
RDTP $_{q}$	MW	*Trade Purchases for Reg-Down for the QSE*—The trade purchases for QSE *q* for Reg-Down for the Operating Hour.

RDTS $_q$	MW	*Trade Sales for Reg-Down for the QSE* — The trade sales for QSE *q* for Reg-Down for the Operating Hour.
TLMP $_y$	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
RNWF $_y$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval y within the Settlement Interval.
RDRWF $_{q, r, ~~p~~, y}$	none	*Regulation Down Resource Node Weighting Factor per interval* - The Reg-Down Resource weight, based on Reg-Down awards, used in the Real-Time MCPC calculation for the portion of the SCED interval y within the Settlement Interval. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
~~*p*~~	~~none~~	~~A Resource Node Settlement Point.~~

(2) Reg-Down Only Charge:

$$\mathbf{RTRDOAMT}_{q} = \quad \mathbf{(1/4) * DARDOAWD}_{q} \mathbf{* RTMCPCRD}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDOAMT $_q$	\$	*Real-Time Reg-Down Only Amount for the QSE* — The total charge to QSE *q* in Real-Time for Reg-Down only awards for each 15-minute Settlement Interval.
DARDOAWD $_q$	MW	*Day-Ahead Reg-Down Only Award for the QSE* — The Reg-Down only capacity awarded in the DAM to the QSE *q* for the Operating Hour.
RTMCPCRD	\$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
q	none	A QSE.

(3) Reg-Down Trade Overage Charge:

$$\mathbf{RTRDTOAMT}_{q} = \quad \mathbf{(1/4) * RTRDTO}_{q} \mathbf{* RTMCPCRD}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDTOAMT $_q$	\$	*Real-Time Reg-Down Trade Overage Amount for the QSE* — The total charge to QSE *q* in Real-Time for Reg-Down trade overages for each 15-minute Settlement Interval.
RTRDTO $_q$	MW	*Real-Time Reg-Down Trade Overage for the QSE* — The quantity of submitted Reg-Down trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour.

RTMCPCRD	\$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.4 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.4 Responsive Reserve Payments and Charges

(1) RRS Imbalance Payment or Charge:

$$\mathbf{RTRRIMBAMT}_{q} = (-1) * [\sum_{r} [\mathbf{RTRRREV}_{q,r} - (1/4) * (\mathbf{PCRRR}_{r,q,DAM} * \mathbf{RTMCPCRR})] - (1/4) * (\mathbf{DASARRQ}_{q} * \mathbf{RTMCPCRR}) + (1/4) * (\mathbf{RRTP}_{q} - \mathbf{RRTS}_{q}) * \mathbf{RTMCPCRR}]$$

Where:

$$\mathbf{RTRRREV}_{q,r} = (1/4) * \mathbf{RTRRAWD}_{q,r} * \mathbf{RTMCPCRRR}_{q,r}$$

$$\mathbf{RTMCPCRRR}_{q,r} = \sum_{y} (\mathbf{RRRWF}_{q,r,\cancel{p},y} * (\mathbf{RTMCPCRRS}_{y} + \mathbf{RTRDPARRS}_{y}))$$

$$\mathbf{RTRRAWD}_{q,r} = \sum_{y} (\mathbf{RNWF}_{y} * \mathbf{RTRRAWDS}_{q,r,\cancel{p},y})$$

Where:

$$\text{RRRWF}_{q,r,\cancel{p},y} = [\max(0.001, \text{RTRRAWDS}_{q,r,\cancel{p},y}) * \text{TLMP}_{y}] / [\sum_{y} \max(0.001, \text{RTRRAWDS}_{q,r,\cancel{p},y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRRIMBAMT_{q}	\$	*Real-Time Responsive Reserve Imbalance Amount for the QSE* The total payment or charge to QSE q for the Real-Time RRS imbalance for each 15-minute Settlement Interval.
$\text{RTRRAWD}_{q,r}$	MW	*Real-Time Responsive Reserve Award per Resource per QSE* The RRS amount awarded to QSE q for Resource r in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.

RTRRREV $_{q, r}$	$	*Real-Time Responsive Reserve Revenue*—The Real-Time RRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTRDPARRS $_{y}$	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Responsive Reserve per SCED interval*—The Real-Time price adder for RRS that captures the impact of reliability deployments on RRS prices for the SCED interval y.
RTRRAWDS $_{q, r, y}$	MW	*Real-Time Responsive Reserve Award per Resource per QSE per SCED interval* - The RRS amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCRRR $_{q, r}$	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve per Resource per QSE*—The Real-Time MCPC for RRS for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMCPCRRS $_{y}$	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve per SCED interval* - The Real-Time MCPC for RRS for the SCED interval *y*.
PCRRR $_{r, q, DAM}$	MW	*Procured Capacity for Responsive Reserve per Resource per QSE in DAM*—The RRS capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCRR	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
DASARRQ $_{q}$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
RRTP $_{q}$	MW	*Trade Purchases for Responsive Reserve for the QSE*—The trade purchases for QSE *q* for RRS for the Operating Hour.
RRTS $_{q}$	MW	*Trade Sales for Responsive Reserve for the QSE*—The trade sales for QSE *q* for RRS for the Operating Hour.
TLMP $_{y}$	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval y within the Settlement Interval.
RRRWF $_{q, r, y}$	none	*Responsive Reserve Resource Node Weighting Factor per interval* - The RRS Resource weight, based on RRS awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.

~~*p*~~	~~none~~	~~A Resource Node Settlement Point.~~

(2) RRS Only Charge:

$$\textbf{RTRROAMT}_{q} = (1/4) * \textbf{DARROAWD}_{q} * \textbf{RTMCPCRR}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRROAMT $_q$	$	*Real-Time Responsive Reserve Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for RRS only awards for each 15-minute Settlement Interval.
DARROAWD $_q$	MW	*Day-Ahead Responsive Reserve Only Award for the QSE*— The RRS only capacity awarded in the DAM to the QSE *q* for the Operating Hour.
RTMCPCRR	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
q	none	A QSE.

(3) RRS Trade Overage Charge:

$$\textbf{RTRRTOAMT}_{q} = (1/4) * \textbf{RTRRTO}_{q} * \textbf{RTMCPCRR}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRRTOAMT $_q$	$	*Real-Time Responsive Reserve Trade Overage Amount for the QSE* - The total charge to QSE *q* in Real-Time for RRS trade overages for each 15-minute Settlement Interval.
RTRRTO $_q$	MW	*Real-Time Responsive Reserve Trade Overage for the QSE* - The quantity of submitted RRS trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour.
RTMCPCRR	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.5 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.5 Non-Spinning Reserve Service Payments and Charges

(1) Non-Spin Imbalance Payment or Charge:

$$\textbf{RTNSIMBAMT}_{q} = (-1) * [\sum_{r} [\textbf{RTNSREV}_{q,r} - (1/4) * (\textbf{PCNSR}_{r,q,DAM} * \textbf{RTMCPCNS})] - (1/4) * (\textbf{DASANSQ}_{q} *$$

RTMCPCNS) + (1/4) * (NSTP $_q$ – NSTS $_q$) * RTMCPCNS]

Where:

$$\textbf{RTNSREV}_{q,r} = (1/4) * \textbf{RTNSAWD}_{q,r} * \textbf{RTMCPCNSR}_{q,r}$$

$$\textbf{RTMCPCNSR}_{q,r} = \sum_{y} (\textbf{NSRWF}_{q,r,p,y} * (\textbf{RTMCPCNSS}_{y} + \textbf{RTRDPANSS}_{y}))$$

$$\textbf{RTNSAWD}_{q,r} = \sum_{y} (\textbf{RNWF}_{y} * \textbf{RTNSAWDS}_{q,r,p,y})$$

Where:

$$\text{NSRWF}_{q,r,p,y} = [\max(0.001, \text{RTNSAWDS}_{q,r,p,y}) * \text{TLMP}_{y}] / [\sum_{y} \max(0.001, \text{RTNSAWDS}_{q,r,p,y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTNSIMBAMT $_q$	$	*Real-Time Non-Spin Imbalance Amount for the QSE* – The total payment or charge to QSE *q* for the Real-Time Non-Spin imbalance for each 15-minute Settlement Interval.
RTNSAWD $_{q,r}$	MW	*Real Time Non-Spin Award per Resource per QSE* - The Non-Spin amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTNSREV $_{q,r}$	$	*Real-Time Non-Spin Revenue* – The Real-Time Non-Spin revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTNSAWDS $_{q,r,p,y}$	MW	*Real Time Non-Spin Award per Resource per QSE per SCED interval* - The Non-Spin Amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCNSR $_{q,r}$	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin per Resource per QSE* – The Real-Time MCPC for Non-Spin for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMCPCNSS $_y$	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin per SCED Interval* - The Real-Time MCPC for Non-Spin for the SCED interval *y*.

PCNSR $_{r, q, (h)}$	MW	*Procured Capacity for Non-Spin per Resource per QSE in DAM* - The Non-Spin capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCNS	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
RTRDPANSS $_y$	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for Non-Spin per SCED interval* - The Real-Time price adder for Non-Spin that captures the impact of reliability deployments on Non-Spin prices for the SCED interval *y*.
DASANSQ $_q$	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE* - The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the DAM for the Operating Hour.
NSTP $_q$	MW	*Trade Purchases for Non-Spin for the QSE* - The trade purchases for QSE *q* for Non-Spin for the Operating Hour.
NSTS $_q$	MW	*Trade Sales for Non-Spin for the QSE*— The trade sales for QSE *q* for Non-Spin for the Operating Hour.
TLMP $_y$	second	*Duration of SCED interval per interval* - The duration of the SCED interval *y*.
RNWF $_y$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval y within the Settlement Interval.
NSRWF $_{q, r, ~~p~~, y}$	none	*Non-Spin Resource Node Weighting Factor per interval* - The Non-Spin Resource weight, based on Non-Spin awards, used in the Real-Time MCPC calculation for the portion of the SCED interval *y* within the Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
~~*p*~~	~~none~~	~~A Resource Node Settlement Point.~~

(2) Non-Spin Only Charge:

$$\mathbf{RTNSOAMT}_{q} = \quad \mathbf{(1/4) * DANSOAWD}_{q} \mathbf{* RTMCPCNS}$$

The above variables are defined as follows:

Variable	Unit	Description
RTNSOAMT $_q$	$	*Real-Time Non-Spin Only Amount for the QSE*— The total charge to QSE *q* in Real-Time for Non-Spin only award for each 15-minute Settlement Interval.
DANSOAWD $_q$	MW	*Day-Ahead Non-Spin Only Award for the QSE*— The Non-Spin only capacity awarded in the DAM to the QSE *q* for the Operating Hour.

RTMCPCNS	\$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
q	none	A QSE.

(3) Non-Spin Trade Overage Charge:

$$\mathbf{RTNSTOAMT}_{q} = \mathbf{(1/4) * RTNSTO}_{q} \mathbf{* RTMCPCRNS}$$

The above variables are defined as follows:

Variable	Unit	Description
RTNSTOAMT $_q$	\$	*Real-Time Non-Spin Trade Overage Amount for the QSE*— The total charge to QSE *q* in Real-Time for Non-Spin trade overages for each 15-minute Settlement Interval.
RTNSTO $_q$	MW	*Real-Time Non-Spin Trade Overage for the QSE* — The quantity of submitted Non-Spin trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour.
RTMCPCNS	\$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.6 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.6 ERCOT Contingency Reserve Service Payments and Charges

(1) ECRS Imbalance Payment or Charge:

$$\mathbf{RTECRIMBAMT}_{q} = \mathbf{(-1) * [} \sum_{r} \mathbf{[RTECRREV}_{q,\,r} \mathbf{- (1/4) * (PCECRR}_{r,\,q,\,DAM} \mathbf{* RTMCPCECR)] - (1/4) * (DASAECRQ}_{q} \mathbf{* RTMCPCECR) + (1/4) * (ECRTP}_{q} \mathbf{- ECRTS}_{q}\mathbf{) * RTMCPCECR]}$$

Where:

$$\mathbf{RTECRREV}_{q,\,r} = \mathbf{(1/4) * RTECRAWD}_{q,\,r} \mathbf{* RTMCPCECRR}_{q,\,r}$$

$$\mathbf{RTMCPCECRR}_{q,\,r} = \sum_{y} \mathbf{(ECRRWF}_{q,\,r,\,p,\,y} \mathbf{* (RTMCPCECRS}_{y} \mathbf{+ RTRDPAECRS}_{y}\mathbf{))}$$

$$\mathbf{RTECRAWD}_{q,r} = \sum_{y} \mathbf{(RNWF}_{y} \mathbf{* RTECRAWDS}_{q,\,r,\,p,\,y}\mathbf{)}$$

Where:

$$\text{ECRRWF}_{q,\,r,\,\cancel{p},\,y} = [\max(0.001, \text{RTECRAWDS}_{q,\,r,\,\cancel{p},\,y}) * \text{TLMP}_{y}] \,/\, [\sum_{y} \max(0.001, \text{RTECRAWDS}_{q,\,r,\,\cancel{p},\,y}) * \text{TLMP}_{y}]$$

And:

$$\text{RNWF}_{y} = \text{TLMP}_{y} \,/\, \sum_{y} \text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTECRIMBAMT_{q}	$	*Real-Time ERCOT Contingency Reserve Service Imbalance Amount for the QSE* – The total payment or charge to QSE *q* for the Real-Time ECRS imbalance for each 15-minute Settlement Interval.
$\text{RTECRAWD}_{q,r}$	MW	*Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE*— The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$\text{RTECRREV}_{q,r}$	$	*Real-Time ERCOT Contingency Reserve Service Revenue*— The Real-Time ECRS revenue for QSE *q* calculated for Resource *r* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{RTECRAWDS}_{q,\,r,\,\cancel{p},\,y}$	MW	*Real-Time ERCOT Contingency Reserve Service Award per Resource per QSE per SCED interval* - The ECRS amount awarded to QSE *q* for Resource *r* in Real-Time for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$\text{RTMCPCECRR}_{q,r}$	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per Resource per QSE* — The Real-Time MCPC for ECRS for Resource *r*, represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTMCPCECRS_{y}	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per SCED Interval* – The Real-Time MCPC for ECRS for the SCED interval *y*.
$\text{PCECRR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per Resource per QSE in DAM* – The ECRS capacity awarded to QSE *q* in the DAM for Resource *r* for the Operating Hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service* – The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
RTRDPAECRS_{y}	$/MW	*Real-Time Reliability Deployment Price Adder for Ancillary Service for ERCOT Contingency Reserve Service per SCED interval* - The Real-Time price adder for ECRS that captures the impact of reliability deployments on ECRS prices for the SCED interval *y*.

DASAECRQ $_q$	MW	*Day-Ahead Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE*—The self-arranged ECRS quantity submitted by QSE q before 1000 in the DAM for the Operating Hour.
ECRTP $_q$	MW	*Trade Purchases for ERCOT Contingency Reserve Service for the QSE*— The trade purchases for QSE q for ECRS for the Operating Hour.
ECRTS $_q$	MW	*Trade Sales for ERCOT Contingency Reserve Service for the QSE*— The trade sales for QSE q for ECRS for the Operating Hour.
TLMP $_y$	second	*Duration of SCED interval per interval* - The duration of the SCED interval y.
RNWF $_y$	none	*Resource Node Weighting Factor per interval* - The weight used in the Ancillary Service award calculation for the portion of the SCED interval y within the Settlement Interval.
ECRRWF $_{q, r, \cancel{p}, y}$	none	*ERCOT Contingency Reserve Service Resource Node Weighting Factor per interval* - The ECRS Resource weight, based on ECRS awards, used in the Real-Time MCPC calculation for the portion of the SCED interval y within the Settlement Interval. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.
r	none	A Resource.
q	none	A QSE.
y	none	A SCED interval in the 15-minute Settlement Interval.
~~*p*~~	~~none~~	~~A Resource Node Settlement Point.~~

(2) ECRS Only Charge:

$$\mathbf{RTECROAMT}_{q} = \quad \mathbf{(1/4) * DAECROAWD}_{q} \mathbf{* RTMCPCECR}$$

The above variables are defined as follows:

Variable	Unit	Description
RTECROAMT $_q$	$	*Real-Time ERCOT Contingency Reserve Service Only Amount for the QSE*— The total charge to QSE q in Real-Time for ECRS only awards for each 15-minute Settlement Interval.
DAECROAWD $_q$	MW	*Day-Ahead ERCOT Contingency Service Only Award for the QSE*—The ECRS only capacity awarded in the DAM to the QSE q for the Operating Hour.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service* — The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
q	none	A QSE.

(3) ECRS Trade Overage Charge:

$$\mathbf{RTECRTOAMT}_{q} = \quad \mathbf{(1/4) * RTECRTO}_{q} \mathbf{* RTMCPCRECR}$$

The above variables are defined as follows:

Variable	Unit	Description
RTECRTOAMT $_q$	$	*Real-Time ERCOT Contingency Reserve Service Trade Overage Amount for the QSE*—The total charge to QSE *q* in Real-Time for ECRS trade overages for each 15-minute Settlement Interval.
RTECRTO $_q$	MW	*Real-Time ERCOT Contingency Reserve Service Trade Overage for the QSE*—The quantity of submitted ECRS trades in excess of their DAM self-arrangement quantity for the QSE *q* for the Operating Hour.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service*—The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
q	none	A QSE.

[NPRR1010: Insert Section 6.7.5.7 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.7 Real-Time Derated Ancillary Service Capability Payment

(1) If ERCOT manually reduces the amount of an Ancillary Service that may be awarded to a Resource in Real-Time under paragraph (6) of Section 6.4.9.1.1, Ancillary Service Awards, and the reduction reduces the payment the QSE would have received under Section 6.7.5.1, Real-Time Ancillary Service Imbalance Payment or Charge, the QSE may be eligible for a Real-Time derated Ancillary Service capability payment under this Section.

(2) In order to be eligible for a Real-Time derated Ancillary Service capability payment, the QSE must:

(a) File a timely Settlement and billing dispute, identifying the following items, by Settlement Interval:

(i) Dollar amount and calculation of the estimated Real-Time derated Ancillary Service capability payment;

(ii) The quantity of Ancillary Service awards, by Ancillary Service product, that were not awarded due to ERCOT's manual reduction of the Resource's Ancillary Service capability;

(iii) Any additional revenues earned by the QSE under Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node; and

(iv) Any additional revenues earned by the QSE under Section 6.7.5.1, Real-Time Ancillary Service Imbalance Payment or Charge.

(b) Have submitted an Ancillary Service Offer for the disputed Settlement Interval(s). The Ancillary Service Offer used to calculate the Real-Time derated Ancillary Service capability payment shall be the most recent offer received by ERCOT effective for the disputed Settlement Interval(s) before ERCOT manually reduced the amount of Ancillary Service to be awarded.

(3) ERCOT shall attempt to validate the calculations provided by the QSE, and may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 Business Days of ERCOT's request. Upon determination by ERCOT that no additional supporting documentation or explanation is needed from the disputing QSE, ERCOT shall notify the QSE of its acceptance or rejection of the claim for the Real-Time derated Ancillary Service capability payment within 15 Business Days.

(4) The price used to determine the derated MWs that were not awarded due to the manual reduction shall be the Real-Time MCPC for the Ancillary Service that was reduced.

(5) The amount recoverable under this section shall be capped by the Real-Time MCPC for the Ancillary Service that was reduced, multiplied by the reduced quantity.

(6) The amount recoverable under this Section shall be reduced by any additional revenue received by the QSE, as determined in paragraphs (2)(a)(iii) and (2)(a)(iv) above.

(7) The Real-Time derated Ancillary Service capability payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTDASAMT}_{q} = (-1) * \underline{\mathbf{Max\ [0,}}\ \mathbf{Min\ [(RTRUILD}_{q} + \mathbf{RTRDILD}_{q} + \mathbf{RTRRILD}_{q} + \mathbf{RTNSILD}_{q} + \mathbf{RTECRILD}_{q} - \mathbf{RTEIRD}_{q} - \mathbf{RTASIRD}_{q}),\ \sum_{r} \mathbf{RTDASCAP}_{q,r}\underline{]]}$$

Where:

$$\text{RTDASCAP}_{q,r} = (1/4) * (\text{RTMCPCRU} * \text{RTRUDQ}_{q,r} + \text{RTMCPCRD} * \text{RTRDDQ}_{q,r} + \text{RTMCPCRR} * \text{RTRRDQ}_{q,r} + \text{RTMCPCNS} * \text{RTNSDQ}_{q,r} + \text{RTMCPCECR} * \text{RTECRDQ}_{q,r})$$

The above variables are defined as follows:

Variable	Unit	Description
RTDASAMT_{q}	$	*Real-Time Derated Ancillary Service Amount*—The payment to QSE *q* for amounts recoverable resulting from a manual reduction of Ancillary Services by ERCOT for the 15-minute Settlement Interval.

RTRUILD $_q$	$	*Real-Time Derated Regulation Up Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.2, Regulation Up Service Payments and Charges, for the 15-minute Settlement Interval.
RTRDILD $_q$	$	*Real-Time Derated Regulation Down Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.3, Regulation Down Service Payments and Charges, for the 15-minute Settlement Interval.
RTRRILD $_q$	$	*Real-Time Derated Responsive Reserve Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.4, Responsive Reserve Payments and Charges, for the 15-minute Settlement Interval.
RTNSILD $_q$	$	*Real-Time Derated Non-Spin Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.5, Non-Spinning Reserve Service Payments and Charges, for the 15-minute Settlement Interval.
RTECRILD $_q$	$	*Real-Time Derated ERCOT Contingency Reserve Service Imbalance Losses for Deration*—The payments not made to QSE *q* under paragraph (1) of Section 6.7.5.6, ERCOT Contingency Reserve Service Payments and Charges, for the 15-minute Settlement Interval.
RTEIRD $_q$	$	*Real-Time Energy Imbalance Revenues for Deration*—The additional payments to QSE *q* under Section 6.6.3.1.
RTASIRD $_q$	$	*Real-Time Ancillary Service Imbalance Revenues for Deration*—The additional Ancillary Service imbalance payments to QSE *q* for all Ancillary Service products for the 15-minute Settlement Interval.
RTDASCAP $_{q,r}$	$	*Real-Time Derated Ancillary Service Payment Cap*—The amount recoverable for Resource *r* represented by QSE *q*, capped by the Real-Time MCPC for the Ancillary Service product that was derated, multiplied by the quantity by which the Resource's capability to provide the Ancillary Service was reduced for the 15-minute Settlement Interval. <u>Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</u>
RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Regulation Up* - The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
RTMCPCRD	$/MW	*Real-Time Market Clearing Price for Capacity for Regulation Down* - The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
RTMCPCRR	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve* - The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
RTMCPCNS	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin* - The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service* — The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
RTRUDQ $_{q,r}$	MW	*Real-Time Regulation Up Derated Quantity* - The Reg-Up quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval. <u>Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</u>
RTRDDQ $_{q,r}$	MW	*Real-Time Regulation Down Derated Quantity* - The Reg-Down quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval. <u>Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.</u>

RTRRDQ $_{q,r}$	MW	*Real-Time Responsive Reserve Derated Quantity* - The RRS quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTECRDQ $_{q,r}$	MW	*Real-Time ERCOT Contingency Reserve Service Derated Quantity* - The ECRS quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
RTNSDQ $_{q,r}$	MW	*Real-Time Non-Spin Derated Quantity* - The Non-Spin quantity manually reduced by ERCOT for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	A Resource.

[NPRR1010: Insert Section 6.7.5.8 below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.7.5.8 Real-Time Derated Ancillary Service Capability Charge

(1) The total cost for Real-Time derated Ancillary Service payments ~~and charges~~ is allocated to QSEs representing Load based on Load Ratio Share (LRS). The Real-Time derated Ancillary Service Payment allocations to each QSE for a given 15-minute Settlement Interval are calculated as follows:

$$\text{LARTDASAMT}_{q} = (-1) * \text{RTDASAMTTOT} * \text{LRS}_{q}$$

Where:

$$\text{RTDASAMTTOT} = \sum_{q} \text{RTDASAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
LARTDASAMT $_{q}$	\$	*Load Allocated Real-Time Derated Ancillary Service Amount per QSE* - The charge to QSE *q* due to a manual reduction of Ancillary Services to be awarded for the 15-minute Settlement Interval.
RTDASAMTTOT	\$	*Real-Time Derated Ancillary Service Amount Total* - The total of all payments to all QSEs for amounts recoverable due to an ERCOT issued manual reduction of Ancillary Services to be awarded for the 15-minute Settlement Interval.
RTDASAMT $_{q}$	\$	*Real-Time Derated Ancillary Service Amount* - The payment to QSE *q* for amounts recoverable due to an ERCOT issued manual reduction of Ancillary Services to be awarded for the 15-minute Settlement Interval.
LRS $_{q}$	none	*Load Ratio Share per QSE* - The LRS as defined in Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval, for QSE *q* for the 15-minute Settlement Interval.

q	none	A QSE.

7.9.3.1 DAM Congestion Rent

(1) The DAM congestion rent is calculated as the sum of the following payments and charges:

(a) The total of payments to all QSEs for cleared DAM energy offers, whether through Three-Part Supply Offers, ~~or through~~ DAM Energy-Only Offer Curves, or cleared sales from the offer portion of Energy Bid/Offer Curves, calculated under Section 4.6.2.1, Day-Ahead Energy Payment;

(b) The total of charges to all QSEs for cleared DAM Energy Bids or cleared purchases from the bid portion of Energy Bid/Offer Curves, calculated under Section 4.6.2.2, Day-Ahead Energy Charge; and

[NPRR1188: Replace item (b) above with the following upon system implementation:]

(b) The total of charges to all QSEs for cleared DAM Energy Bids and Energy Bid Curves, calculated under Section 4.6.2.2, Day-Ahead Energy Charge; and

(c) The total of charges or payments to all QSEs for PTP Obligation bids cleared in the DAM, calculated under Section 4.6.3, Settlement for PTP Obligations Bought in DAM.

(d) The total of charges to all QSEs for PTP Obligation with Links to an Option bids cleared in the DAM, calculated under Section 4.6.3.

(2) The DAM congestion rent for a given Operating Hour is calculated as follows:

$$\mathbf{DACONGRENT} = \mathbf{DAESAMTTOT + DAEPAMTTOT + DARTOBLAMTTOT + DARTOBLLOAMTTOT}$$

Where:

$$\text{DAESAMTTOT} = \sum_{q} \text{DAESAMTQSETOT}_{q}$$

$$\text{DAEPAMTTOT} = \sum_{q} \text{DAEPAMTQSETOT}_{q}$$

$$\text{DARTOBLAMTTOT} = \sum_{q} \text{DARTOBLAMTQSETOT}_{q}$$

$$\text{DARTOBLLOAMTTOT} = \sum_{q} \text{DARTOBLLOAMTQSETOT}_{q}$$

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The above variables are defined as follows:

Variable	Unit	Definition
DACONGRENT	$	*Day-Ahead Congestion Rent*—The congestion rent collected in the DAM for the hour.
DAESAMTTOT	$	*Day-Ahead Energy Sale Amount Total*—The total payment to all QSEs for cleared DAM energy offers, whether through Three-Part Supply Offers, ~~or through~~ DAM Energy-Only Offer Curves, or cleared sales from the offer portion of Energy Bid/Offer Curves, for the hour. ***[NPRR1188: Replace definition above with the following upon system implementation:]*** *Day-Ahead Energy Purchase Amount Total*—The total charge to all QSEs for DAM Energy Bids and Energy Bid Curves, cleared in the DAM, for the hour.
DAEPAMTTOT	$	*Day-Ahead Energy Purchase Amount Total*—The total charge to all QSEs for cleared DAM Energy Bids or cleared purchases from the bid portion of Energy Bid/Offer Curves for the hour.
DARTOBLAMTTOT	$	*Day-Ahead Real-Time Obligation Amount Total*—The net total charge or payment to all QSEs for cleared PTP Obligation bids in the DAM for the hour.
DARTOBLLOAMTTOT	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount Total*—The net total charge to all QSEs for charge to QSE *q* for a PTP Obligation with Links to an Option Bid cleared in the DAM with the source *j* and the sink *k*, for the hour.
DAESAMTQSETOT $_q$	$	*Day-Ahead Energy Sale Amount QSE Total per QSE*—The total payment to QSE *q* for cleared DAM energy offers, whether through Three-Part Supply Offers, ~~or through~~ DAM Energy-Only Offer Curves, or cleared sales from the offer portion of Energy Bid/Offer Curves, for the hour. See item (2) of Section 4.6.2.1.
DAEPAMTQSETOT $_q$	$	*Day-Ahead Energy Purchase Amount QSE Total per QSE*—The total charge to QSE *q* for cleared DAM Energy Bids or cleared purchases from the bid portion of Energy Bid/Offer Curves for the hour. See item (2) of Section 4.6.2.2. ***[NPRR1188: Replace definition above with the following upon system implementation:]*** *Day-Ahead Energy Purchase Amount QSE Total per QSE*—The total charge to QSE *q* for DAM Energy Bids and Energy Bid Curves, cleared in the DAM, for the hour. See item (2) of Section 4.6.2.2.
DARTOBLAMTQSETOT $_q$	$	*Day-Ahead Real-Time Obligation Amount QSE Total per QSE*—The total charge or payment to QSE *q* for PTP Obligation Bids cleared in the DAM for the hour. See item (2) of Section 4.6.3.
DARTOBLLOAMTQSETOT$_q$	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The net total charge to QSE q for all its PTP Obligation with Links to an Option Bids cleared in the DAM for the hour.
q	none	A QSE.

9.14.10 Settlement for Market Participants Impacted by Omitted Procedures or Manual Actions to Resolve the DAM

Commented [CP6]: Please note NPRR1235 also proposes revisions to this section.

(1) A Market Participant that has been directly impacted by an action or omission by ERCOT to resolve the DAM, as described in paragraph (4) of Section 4.1.2, Day-Ahead Process and Timing Deviations, may seek recovery by filing a Settlement and billing dispute as defined in Section 9.14. Where ERCOT determines that the Market Participant seeking recovery has been directly impacted by such ERCOT action or omission, the following provisions apply:

(a) No resettlement of the DAM will occur as a result of a Market Participant's recovery under this Section;

(b) Where a Market Participant's submissions were not cleared in the DAM, ERCOT will establish a set of DAM Energy Bids, DAM Energy Offers, Resource-Specific Ancillary Service Offers, Ancillary Service Only Offers, and Point-to-Point (PTP) bids that would have cleared given the settled prices of the DAM;

[NPRR1188: Replace paragraph (b) above with the following upon system implementation:]

(b) Where a Market Participant's submissions were not cleared in the DAM, ERCOT will establish a set of DAM Energy Bids, DAM Energy Offers, Ancillary Service Offers, Energy Bid Curves, and Point-to-Point (PTP) bids that would have cleared given the settled prices of the DAM;

(c) Startup Costs and minimum energy costs will not be considered for recovery;

(d) For linked offers of energy and Ancillary Services, the available capacity will be allocated to the offers that would have created the greatest value for the Market Participant seeking recovery;

(e) All impacted positions will be summed based on their positive or negative value with respect to Real-Time prices;

Day-Ahead Energy Sales Impact

$$\text{DAMSQSEAMT}_{q} = (-1) * \sum_{p} ((\text{DASPP}_{p} - \text{RTSPP}_{p}) * (1/4) * \text{DAES}_{q,\,p})$$

Day-Ahead Energy Purchase Impact

$$\text{DAMPQSEAMT}_{q} = (-1) * \sum_{p} ((\text{RTSPP}_{p} - \text{DASPP}_{p}) * (1/4) * \text{DAEP}_{q,\,p})$$

Day-Ahead Ancillary Services Sales Impact

$$DAMASQSEAMT_{q} = (-1) * \sum_{r} (((MCPCRU_{DAM} - \underline{RTMCPCRU}\cancel{RUOPR_{q,r,DAM}}) * \underline{(1/4) *} PCRUR_{q,r,DAM})$$

$$+ ((MCPCRD_{DAM} - \underline{RTMCPCRD}\cancel{RDOPR_{q,r,DAM}}) * \underline{(1/4) *} PCRDR_{q,r,DAM})$$

$$+ ((MCPCRR_{DAM} - \underline{RTMCPCRR}\cancel{RROPR_{q,r,DAM}}) * \underline{(1/4) *} PCRRR_{q,r,DAM})$$

$$+ ((MCPCECR_{DAM} - \underline{RTMCPCECR}\cancel{ECRSOPR_{q,r,DAM}}) * \underline{(1/4) *} PCECRR_{q,r,DAM})$$

$$+ ((MCPCNS_{DAM} - \underline{RTMCPCNS}\cancel{NSOPR_{q,r,DAM}}) * \underline{(1/4) *} PCNSR_{q,r,DAM})$$

$$\underline{+ ((MCPCRU_{DAM} - RTMCPCRU\cancel{RUOOPR_{q,DAM}}) * (1/4) * DARUOAWD_{q})}$$

$$\underline{+ ((MCPCRD_{DAM} - RTMCPCRD\cancel{RDOOPR_{q,DAM}}) * (1/4) * DARDOAWD_{q})}$$

$$\underline{+ ((MCPCRR_{DAM} - RTMCPCRR\cancel{RROOPR_{q,DAM}}) * (1/4) * DARROAWD_{q})}$$

$$\underline{+ ((MCPCECR_{DAM} - RTMCPCECR\cancel{ECRSOOPR_{q,DAM}}) * (1/4) * DAECROAWD_{q})}$$

$$\underline{+ ((MCPCNS_{DAM} - RTMCPCNS\cancel{NSOOPR_{q,DAM}}) * (1/4) * DANSOAWD_{q}))}$$

Day-Ahead Point-to-Point Obligation Impact

$$DAMRTPTPQSEAMT_{q} = (-1) * \sum_{j} \sum_{k} ((RTOBLPR_{(j,k)} - DAOBLPR_{(j,k)}) * RTOBL_{q,(j,k)})$$

Where:

$$RTOBLPR_{(j,k)} = \sum_{i=1}^{4} (RTSPP_{(k,i)} - RTSPP_{(j,i)}) / 4$$

$$DAOBLPR_{(j,k)} = DASPP_{k} - DASPP_{j}$$

(f) If any RUC short charges occur for any Operating Hour involved in a Market Participant's recovery under this Section, ERCOT will evaluate the Market Participant's revised position to determine if the Market Participant is entitled to a refund, or should be charged for RUC short charge;

(g) Any resulting charge or payment to the Market Participant will be invoiced using a miscellaneous Invoice, but allocated with the method outlined in paragraphs (2) through (4) of Section 9.19.1, Default Uplift Invoices.

The above variables are defined as follows:

Variable	Unit	Definition
DAMSQSEAMT $_q$	$	*Day-Ahead Market Energy Sales Amount by QSE*—The sum of the DAM Energy Sales positions compared to Real-Time results, for the QSE *q*, for the 15-minute Settlement Interval.
DAMPQSEAMT $_q$	$	*Day-Ahead Market Energy Purchases Amount by QSE*—The sum of the DAM Energy purchases compared to Real-Time results, for the QSE *q*, for the 15-minute Settlement Interval.
DAMASQSEAMT $_q$	$	*Day-Ahead Market Ancillary Service Amount by QSE*—The sum of the DAM Ancillary Service awarded amounts compared to Real-Time results, for the QSE *q*, for the 15-minute Settlement Interval~~hour~~.
DAMRTPTPQSEAMT $_q$	$	*Day-Ahead Market Real-Time Point-to-Point Obligation Amount by QSE*—The sum of the PTP Obligation bids cleared in the DAM compared to Real-Time results, for the QSE *q*, for the hour.
DASPP $_p$	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM Settlement Point Price at Settlement Point *p*, for the hour.
RTOBL $_{q, (j, k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total MW of QSE *q*'s PTP Obligation bids that would have cleared in the DAM and settled in Real-Time for the source *j*, and the sink *k*, for the hour.
RTSPP $_p$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point for the 15-minute Settlement Interval within the hour.
DAES $_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s Three-Part Supply Offers that would have cleared in the DAM and DAM Energy-Only Offer Curves that would have cleared in the DAM at Settlement Point *p*, for the hour.
DAEP $_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s DAM Energy Bids that would have cleared at Settlement Point *p*, for the hour. ***[NPRR1188: Replace the definition above with the following upon system implementation:]*** *Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s DAM Energy Bids and Energy Bid Curves that would have cleared in the DAM at Settlement Point *p*, for the hour.
PCRUR $_{q, r, DAM}$	MW	*Procured Capacity for Regulation Up from Resource per QSE per Resource in DAM*—The Regulation Up Service (Reg-Up) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
PCRDR $_{q, r, DAM}$	MW	*Procured Capacity for Regulation Down from Resource per QSE per Resource in DAM*—The Regulation Down Service (Reg-Down) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

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$PCRRR_{q, r, DAM}$	MW	*Procured Capacity for Responsive Reserve from Resource per QSE per Resource in DAM*—The Responsive Reserve (RRS) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$PCNSR_{q, r, DAM}$	MW	*Procured Capacity for Non-Spinning Reserve from Resource per QSE per Resource in DAM*—The Non-Spinning Reserve (Non-Spin) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$PCECRR_{q, r, DAM}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service from Resource per QSE per Resource in DAM*—The ERCOT Contingency Reserve Service (ECRS) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$DARUOAWD_{q}$	MW	*Day-Ahead Reg-Up Only Award per QSE*—The Reg-Up Only capacity quantity that would have been awarded to QSE *q* in the DAM for the hour.
$DARDOAWD_{q}$	MW	*Day-Ahead Reg-Down Only Award per QSE*—The Reg-Down Only capacity quantity that would have been awarded to QSE *q* in the DAM for the hour.
$DARROAWD_{q}$	MW	*Day-Ahead Responsive Reserve Only Award per QSE*—The RRS Only capacity quantity that would have been awarded to QSE *q* in the DAM for the hour.
$DANSOAWD_{q}$	MW	*Day-Ahead Non-Spin Only Award per QSE*—The Non-Spin Only capacity quantity that would have been awarded to QSE *q* in the DAM for the hour.
$DAECROAWD_{q}$	MW	*Day-Ahead ERCOT Contingency Reserve Service Only Award per QSE*—The ECRS Only capacity quantity that would have been awarded to QSE *q* in the DAM for the hour.
~~$RUOPR_{q, r, DAM}$~~	~~$/MW per hour~~	~~*Regulation Up Offer Price*—The offer price for Resource *r* represented by QSE *q*, for the impacted Reg-Up Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.~~
~~$RDOPR_{q, r, DAM}$~~	~~$/MW per hour~~	~~*Regulation Down Offer Price*—The offer price for Resource *r* represented by QSE *q*, for the impacted Reg-Down Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.~~
~~$RROPR_{q, r, DAM}$~~	~~$/MW per hour~~	~~*Responsive Reserve Offer Price*—The offer price for Resource *r* represented by QSE *q*, for the impacted RRS Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.~~
~~$ECRSOPR_{q, r, DAM}$~~	~~$/MW per hour~~	~~*ERCOT Contingency Reserve Service Offer Price*—The offer price for Resource *r* represented by QSE *q*, for the impacted ECRS Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.~~
~~$NSOPR_{q, r, DAM}$~~	~~$/MW per hour~~	~~*Non-Spinning Reserve Offer Price*—The offer price for Resource *r* represented by QSE *q*, for the impacted Non-Spin Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.~~
~~$RUOOPR_{q, DAM}$~~	~~$/MW per hour~~	~~*Regulation Up Only Offer Price*—The offer price for QSE *q* for the impacted Reg-Up Ancillary Service Only Offers.~~

~~RDOOPR $_{q, DAM}$~~	~~$/MW per hour~~	~~*Regulation Down Only Offer Price*—The offer price for QSE *q* for the impacted Reg-Down Ancillary Service Only Offers.~~
~~RROOPR $_{q, DAM}$~~	~~$/MW per hour~~	~~*Responsive Reserve Only Offer Price*—The offer price for QSE *q* for the impacted RRS Ancillary Service Only Offers.~~
~~ECRSOOPR $_{q, DAM}$~~	~~$/MW per hour~~	~~*ERCOT Contingency Reserve Service Only Offer Price*—The offer price for QSE *q* for the impacted ECRS Ancillary Service Only Offers.~~
~~NSOOPR $_{q, DAM}$~~	~~$/MW per hour~~	~~*Non-Spinning Reserve Only Offer Price*—The offer price for QSE *q* for the impacted Non-Spin Ancillary Service Only Offers.~~
MCPCRU $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Regulation Up in DAM*—The DAM Market Clearing Price for Capacity (MCPC) for Reg-Up, for the hour.
MCPCRD $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Regulation Down in DAM*—The DAM MCPC for Reg-Down, for the hour.
MCPCRR $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for RRS, for the hour.
MCPCNS $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spinning Reserve in DAM*—The DAM MCPC for Non-Spin, for the hour.
MCPCECR $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service in DAM*—The DAM MCPC for ECRS, for the hour.
RTMCPCRU	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Up*—The Real-Time MCPC for Reg-Up for the 15-minute Settlement Interval.
RTMCPCRD	$/MW	*Real-Time Market Clearing Price for Capacity for Reg-Down*—The Real-Time MCPC for Reg-Down for the 15-minute Settlement Interval.
RTMCPCRR	$/MW	*Real-Time Market Clearing Price for Capacity for Responsive Reserve*—The Real-Time MCPC for RRS for the 15-minute Settlement Interval.
RTMCPCNS	$/MW	*Real-Time Market Clearing Price for Capacity for Non-Spin*—The Real-Time MCPC for Non-Spin for the 15-minute Settlement Interval.
RTMCPCECR	$/MW	*Real-Time Market Clearing Price for Capacity for ERCOT Contingency Reserve Service*—The Real-Time MCPC for ECRS for the 15-minute Settlement Interval.
DAOBLPR $_{(j, k)}$	$/MWh	*Day-Ahead Obligation Price per pair of source and sink*—The DAM clearing price of a PTP Obligation bid, with the source *j*~~,~~ and the sink *k*, for the hour.
RTOBLPR $_{(j, k)}$	$/MWh	*Real-Time Obligation Price per pair of source and sink*—The Real-Time calculated price of a PTP Obligation bid, with the source *j*~~,~~ and the sink *k*, for the hour ~~15 minute period~~.
q	none	A QSE.
r	none	A Resource.
i	none	A 15-minute Settlement Interval.
k	none	A sink Settlement Point.
p	none	A Settlement Point.
j	none	A source Settlement Point.

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25.5.1 Settlement Activity for a Market Suspension

(1) Settlement for the Operating Days for which the Real-Time Market (RTM) has been suspended shall be limited to the following payments and charges:

(a) Market Suspension Make-Whole Payment;

(b) Market Suspension Direct Current Tie (DC Tie) Import Payment;

(c) Market Suspension Block Load Transfer Payment;

(d) Reliability Must-Run (RMR) Standby Payment;

(e) RMR Payment for Energy;

(f) Black Start Hourly Standby Fee Payment;

(g) Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(h) Market Suspension Charge Allocation; and

(i) ERCOT System Administration Fee.

(2) During a Market Suspension:

(a) To the extent feasible, ERCOT shall calculate and pay the Real-Time Market Suspension Make-Whole Payment to each eligible Qualified Scheduling Entity (QSE).

(b) ERCOT shall wire the funds to the QSE's banking institution as soon as practicable, subject to the availability of funds and the availability of systems for transfer of funds.

(c) At its sole discretion, ERCOT may suspend calculating monthly verifiable cost updates.

(d) ERCOT shall not assess:

(i) Market Suspension Charge Allocation as defined in Section 25.5.5, Market Suspension Charge Allocation;

(ii) Market Suspension DC Tie Import Payment as defined in Section 25.5.3, Market Suspension DC Tie Import Payment;

(iii) Market Suspension Block Load Transfer Payment as defined in Section 25.5.4, Market Suspension Block Load Transfer Payment;

(iv) RMR Standby Payment;

(v) RMR Payment for Energy;

(vi) Black Start Hourly Standby Fee Payment; and

(vii) ERCOT System Administration Fee.

(3) ERCOT may, at its sole discretion, settle the Operating Days that occur during a Market Suspension without use of RTM Settlement Statements, Settlement Invoices, and associated provisions, as described in Section 9, Settlement and Billing.

(4) ERCOT shall maintain available supporting billing determinant Settlement data for Market Suspension Operating Day Settlement and shall provide this information to each QSE as soon as practicable.

(5) ERCOT shall cease to utilize the provisions for Market Suspension Settlement beginning with the first complete Operating Day for which ERCOT issues Dispatch Instructions to QSEs in accordance with Section 25.3, Market Restart Processes.

(6) After Market Restart ERCOT shall:

(a) Reconcile payments to QSEs with Generation Resources or Energy Storage Resources (ESRs) pursuant to Section 25.5.2, Market Suspension Make-Whole Payment, using the best available generation data;

(b) Calculate Market Suspension DC Tie Import Payments as defined in Section 25.5.3;

(c) Calculate Market Suspension Block Load Transfer Payments as defined in Section 25.5.4;

(d) Calculate Market Suspension RMR Standby Payments in accordance with Section 6.6.6.1, RMR Standby Payment;

(e) Calculate Market Suspension RMR Payment for Energy in accordance with Section 6.6.6.2, RMR Payment for Energy;

(f) Calculate Market Suspension Black Start Service in accordance with Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(g) Allocate costs in accordance with Section 25.5.5; and

(h) Assess the ERCOT System Administration Fee for the time period of the Market Suspension in accordance with Section 9.16.1, ERCOT System Administration Fee, using the best available Load data.

(7) ERCOT shall provide Notice no less than two Business Days prior to issuing any reconciliation Settlement for the impacted period.

(8) ERCOT shall resume other Settlement activities that were suspended as a result of, or in relation to, the Market Suspension as soon as practicable following the Market Restart, including, but not limited to, pending Congestion Revenue Right (CRR), Day-Ahead Market (DAM) and RTM Settlement for Operating Days prior to the Market Suspension.

25.5.2 Market Suspension Make-Whole Payment

(1) To compensate QSEs representing Generation Resources for providing energy during a Market Suspension, ERCOT shall calculate a Market Suspension Make-Whole Payment for the Operating Day as follows:

[NPRR1029: Replace paragraph (1) above with the following upon system implementation:]

(1) To compensate QSEs representing Generation Resources or Energy Storage Resources (ESRs) for providing energy during a Market Suspension, ERCOT shall calculate a Market Suspension Make-Whole Payment for the Operating Day as follows:

$$MSMWAMT_{q,r,d} = (-1) * (MSSUC_{q,r,d} + MSOC_{q,r,d} + MSSUCADJ_{q,r,d} + MSOCADJ_{q,r,d})$$

Where,

The startup cost (MSSUC) is calculated as follows:

For Black Start Resources:

$$MSSUC_{q,r,d} = \$0.00$$

For Combined Cycle Trains:

$$MSSUC_{q,r,d} = \sum_{s} MSSUPR_{q,r,s} + \sum_{t} (MAX(0, MSSUPR_{afterCCGR} - MSSUPR_{beforeCCGR}))$$

For all other Resources:

$$MSSUC_{q,r,d} = \sum_{s} MSSUPR_{q,r,s}$$

The startup price (MSSUPR) and operating cost (MSOC) are calculated as follows:

If ERCOT has approved verifiable costs for the Generation Resource:

For Firm Fuel Supply Resources (FFSRs) starting with a reserved fuel

$$MSSUPR_{q,r,s} = RVOMS_{q,r,s}$$

$$MSOC_{q,r,d} = \sum_{i} (ROM_{q,r}) * MSGEN_{q,r,i}$$

Otherwise,

$$MSSUPR_{q,r,s} = RABCFCRS_{q,r,s} * (MSAVGFP + FA_{q,r}) + RVOMS_{q,r,s}$$

$$MSOC_{q,r,d} = \sum_{i} (AHR_{q,r,i} * (MSAVGFP + FA_{q,r}) + ROM_{q,r}) * MSGEN_{q,r,i}$$

If ERCOT has not approved verifiable costs for the Generation Resource:

For FFSRs starting with a reserved fuel

$$MSSUPR_{q,r,s} = RCGSC$$

$$MSOC_{q,r,d} = \sum_{i} (STOM_{rc}) * MSGEN_{q,r,i}$$

Otherwise,

$$MSSUPR_{q,r,s} = RCGSC$$

$$MSOC_{q,r,d} = \sum_{i} (PAHR_{r,i} * (MSAVGFP + PFA_{rc}) + STOM_{rc}) * MSGEN_{q,r,i}$$

Where,

MSAVGFP = MSAVGFIP for Generation Resources that indicate in the Resource Registration process or the verifiable cost process to start on natural gas

[NPRR1029: Replace the formula for "MSAVGP" above with the following upon system implementation:]

MSAVGFP = MSAVGFIP for Generation Resources that indicate in the Resource Registration process or the verifiable cost process to start on natural gas. For ESRs, the MSAVGFIP shall be set to zero.

Or,

MSAVGFP = MSAVGFOP for Generation Resources that indicate in the Resource Registration process or through the verifiable cost process to start on fuel oil

The above variables are defined as follows:

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Variable	Unit	Definition
$MSMWAMT_{q, r, d}$	$	*Market Suspension Make-Whole Payment* – The Market Suspension Make-Whole Payment to the QSE *q*, for Resource *r*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$MSSUCADJ_{q, r, d}$	$	*Market Suspension Startup Costs Adjustment* – Adjustment to the Market Suspension Make-Whole Payment to pay or charge the QSE *q* for actual costs related to starting up Resource *r*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$MSOCADJ_{q, r, d}$	$	*Market Suspension Operating Costs Adjustment* – Adjustment to the Market Suspension Make-Whole Payment to pay or charge the QSE *q* for actual costs for operating Resource *r*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$MSSUC_{q, r, d}$	$	*Market Suspension Startup Cost* – The Startup Costs for Resource *r* represented by QSE *q* during restart hours, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$MSSUPR_{q, r, s}$	$	*Market Suspension Startup Price per Start* – The Market Suspension Settlement price for Resource *r* represented by QSE *q* for the start *s*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$RABCFCRS_{q, r, s}$	MMBtu / start	*Raw Actual Breaker Close Fuel Consumption Rate per Start* – The raw actual verifiable fuel consumption rate, from first fire to breaker close, for the Resource *r* represented by QSE *q*, per start *s*, for the warmth state, as submitted through the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$MSOC_{q, r, d}$	$	*Market Suspension Operating Cost* – The Market Suspension operating cost for Resource *r* represented by QSE *q* for operations after breaker close for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$RVOMS_{q, r, s}$	$/start	*Raw Verifiable Operations and Maintenance Cost per Start* – The raw verifiable Operations and Maintenance (O&M) cost for the Resource *r* represented by QSE *q*, per start *s*, for the warmth state, as submitted through the verifiable cost process. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$ROM_{q, r}$	$/MWh	*Raw Verifiable Operations and Maintenance Cost Above LSL* – The raw verifiable O&M cost for the Resource *r* represented by QSE *q* for operations above Low Sustained Limit (LSL). Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	Unit	Definition
$STOM_{rc}$	$/MWh	*Standard Operations and Maintenance Cost* – The standard O&M cost for the Resource category *rc* for operations above LSL, shall be set to the minimum energy variable O&M costs, as described in paragraph (6)(c) of Section 5.6.1, Verifiable Costs. For an ESR, STOM shall be set at $0.3/MWh. ***[NPRR1029: Replace the definition above with the following upon system implementation:]*** *Standard Operations and Maintenance Cost* – The standard O&M cost for the Resource category *rc* for operations above LSL, shall be set to the minimum energy variable O&M costs, as described in paragraph (6)(c) of Section 5.6.1, Verifiable Costs. For an ESR, STOM shall be set at $0.3/MWh and for a DC-Coupled Resource, the value shall be set at $4.40/MWh.
MSAVGFP	$/MMBtu	*Market Suspension Average Fuel Price* – The Market Suspension average fuel price calculated based on MSAVGFIP or MSAVGFOP.
MSAVGFIP	$/MMBtu	*Market Suspension Average Fuel Index Price* – The Market Suspension average Fuel Index Price (FIP) calculated as the average price of FIP for the 15 days prior to the Market Suspension event, calculated on a daily rolling basis for Operating Days the index price is available to ERCOT.
MSAVGFOP	$/MMBtu	*Market Suspension Average Fuel Oil Price* – The Market Suspension average Fuel Oil Price (FOP) calculated as the average price of FOP for the 15 days prior to the Market Suspension event, calculated on a daily rolling basis for Operating Days the index price is available to ERCOT.
RCGSC	$/start	*Resource Category Generic Startup Cost* – The Resource Category Generic Startup Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$FA_{q, r}$	$/MMBtu	*Verifiable Average Fuel Adder* – The verifiable average fuel price adder for the Resource *r* represented by QSE *q*. The fuel adder shall be set to the actual approved verifiable fuel adder or the standard value defined in the Verifiable Cost Manual. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
PFA_{rc}	$/MMBtu	*Proxy Fuel Adder* – The proxy fuel price adder for the Resource category *rc*. For all thermal Generation Resources, the fuel adder shall be set to $0.50/MMBtu; otherwise, the fuel adder shall be set to $0.00/MMBtu.
$AHR_{q, r, i}$	MMBtu / MWh	*Average Heat Rate per Resource* – The verifiable average heat rate for the Resource *r* represented by QSE *q*, for operating levels between LSL and High Sustained Limit (HSL), for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$PAHR_{r, i}$	MMBtu / MWh	*Proxy Average Heat Rate* – The proxy average heat rate for the Resource *r* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$MSGEN_{q, r, i}$	MWh	*Market Suspension Generation per Resource* – The generation for the Resource *r* represented by QSE *q* for the 15-minute Settlement Interval *i*.
q	None	A QSE.

Variable	Unit	Definition
r	None	A Generation Resource. ***[NPRR1029: Replace the definition above with the following upon system implementation:]*** A Generation Resource or ESR.
d	None	An Operating Day during a Market Suspension event.
i	None	A 15-minute Settlement Interval within the hour of an Operating Day of a Market Suspension event.
s	None	A Generation Resource start during an Operating Day of a Market Suspension event.
t	None	A transition that is eligible to have its costs included in the Market Suspension Startup Cost.
rc	None	A Resource category.
afterCCGR	None	The Combined Cycle Generation Resource to which a Combined Cycle Train transitions.
beforeCCGR	None	The Combined Cycle Generation Resource from which a Combined Cycle Train transitions.

(2) The total compensation to each QSE for the Market Suspension Make-Whole Payment for an Operating Day is calculated as follows:

$$\mathbf{MSMWAMTQSETOT}_{\,q,\,d} \;=\; \sum_{r} \mathbf{MSMWAMT}_{\,q,\,r,\,d}$$

And,

$$\text{MSMWAMTTOT}_{\,d} \;=\; \sum_{q} \text{MSMWAMTQSETOT}_{\,q,\,d}$$

The above variables are defined as follows:

Variable	Unit	Definition
MSMWAMTQSETOT $_{q,\,d}$	$	*Market Suspension Make-Whole Payment per QSE* – The total payment to QSE *q* for Market Suspension Make-Whole Payment for the Operating Day *d*.
MSMWAMTTOT $_{d}$	$	*Market Suspension Make-Whole Payment Total* – The total payment to all QSEs for Market Suspension Make-Whole Payment for the Operating Day.
MSMWAMT $_{q,\,r,\,d}$	$	*Market Suspension Make-Whole Payment* – The Market Suspension Make-Whole Payment to the QSE *q*, for Resource *r*, for the Operating Day *d*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.

Variable	Unit	Definition
r	none	A Generation Resource. ***[NPRR1029: Replace the definition above with the following upon system implementation:]*** A Generation Resource or ESR.
d	none	An Operating Day during a Market Suspension event.

(3) During a Market Suspension, ERCOT may cease making payments in accordance with this Section in the event that funds are not available to make such payments.

ERCOT Impact Analysis Report

NPRR Number	**<u>1245</u>**	**NPRR Title**	**Additional Clarifying Revisions to Real-Time Co-Optimization**
Impact Analysis Date	July 30, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon implementation of PR447, Real-Time Co-Optimization (RTC). See Comments.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NPRR beyond what was captured in PR447, Real-Time Co-optimization.

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NPRR Number	<u>1247</u>	NPRR Title	**Incorporation of Congestion Cost Savings Test in Economic Evaluation of Transmission Projects**
Date of Decision	December 3, 2024		
Action	Recommended Approval		
Timeline	Urgent		
Estimated Impacts	Cost/Budgetary: Annual Recurring Operations and Maintenance (O&M) Between $360k and $440k (2 FTEs) 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	3.11.2, Planning Criteria		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) incorporates the consumer energy cost reduction test as the congestion cost savings test in economic project evaluation to address recent amendments by the PUCT to 16 Texas Administrative Code § 25.101 — specifically adding the requirements in § 25.101(b)(3)(A)(i). Consistent with the PUCT's rule, this NPRR also preserves the production cost savings test as another standalone means to establish economic need for a transmission project. This NPRR also removes obsolete language regarding transmission projects' benefits evaluation in paragraph (6) of Section 3.11.2. Additional details regarding how the congestion cost savings test will be performed are included in the <u>*Congestion Cost Savings Test Evaluation Guideline*</u> white paper, which will be available on the Planning page of the ERCOT website once finalized. ERCOT may also apply the longstanding <u>*Impact of Weather Uncertainty and Transmission Outages on Economic Project Evaluations*</u> white paper		

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	in the instances specified therein to evaluate the impact of weather uncertainties and the impact of including transmission outages on the congestion cost savings test, as it has for the production cost savings test. This white paper is also available on the Planning page of the ERCOT website.
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	As required by 16 Texas Administrative Code § 25.101(b)(3)(A)(i), as amended in PUCT Project No. 53403, ERCOT, in consultation with PUCT Staff, must develop a congestion cost savings test to be used in economic project evaluation. ERCOT retained Energy + Environmental Economics, Inc. (E3) to identify a set of viable options and provide recommendations of the most suitable congestion cost savings test based on the ERCOT market structure. E3 presented its work at the September 2023 Planning Working Group (PLWG) meeting and recommended system-wide energy cost reduction (referred to in E3's analysis as a "System-Wide Gross Load Cost (GLC) Test") as the most suitable congestion cost savings test for the ERCOT Region. ERCOT worked with PUCT Staff to review the E3 recommendation, considered stakeholder feedback, and agreed with E3's recommendation. This NPRR incorporates the recommended congestion cost savings test in ERCOT's economic project evaluation.
PRS Decision	On 9/12/24, PRS voted unanimously to table NPRR1247 and refer the issue to ROS. All Market Segments participated in the vote.

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	On 11/14/24, PRS voted to grant NPRR1247 Urgent status; to recommend approval of NPRR1247 as amended by the 11/11/24 ERCOT comments; and to forward to TAC NPRR1247 and the 8/9/24 Impact Analysis. There were two opposing votes from the Cooperative (STEC) and Independent Generator (Luminant) Market Segments, and four abstentions from the Independent Generator (Constellation), Independent Power Marketer (IPM) (Tenaska), and Independent Retail Electric Provider (IREP) (2) (Reliant, Chariot) Market Segments. All Market Segments participated in the vote.
Summary of PRS Discussion	On 9/12/24, participants declined to grant Urgent status, requested additional process details, and tabled NPRR1247 for further review by PLWG. On 11/14/24, participants recounted recent PLWG and ROS discussions and reviewed the 11/11/24 ERCOT comments. ERCOT Staff requested Urgency to qualify for consideration at the December 3, 2024 ERCOT Board meeting and reiterated the preference to exclude white paper references from the Protocols, citing their separate approval process. Some stakeholders expressed concern regarding incomplete details and possible suboptimal outcomes that might arise from the expedited stakeholder process. ERCOT Staff confirmed a forthcoming Planning Guide Revision Request (PGRR) to provide additional detail.
TAC Decision	On 11/20/24, TAC voted to recommend approval of NPRR1247 as recommended by PRS in the 11/14/24 PRS Report. There were three opposing votes from the Independent Generator (2) (Calpine, Luminant) and IPM (Shell) Market Segments; and one abstention from the IREP (Reliant) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/20/24, opponents reiterated concerns regarding incomplete congestion process information, planning model details, supporting data and analysis, and white paper language; noted possible negative effects of expedited stakeholder review; and requested additional discussion regarding relevant large load issues. Supporters acknowledged time constraints, emphasized a need to comply with established PUCT rule and legislature, and welcomed continued evolution of the process through submission of future Revision Requests.
Explanation of Opposing TAC Votes	**Independent Generator/Calpine** – Opposed to urgency and the incompleteness of the NPRR. It references white papers/processes which aren't yet available for market review.

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	Independent Generator/Luminant – Luminant submitted written comments on October 28, 2024 and November 15, 2024 that reflect Luminant's concerns with NPRR1247. Luminant believes that the selected Gross Load Cost test methodology overstates the actual net benefits associated with the test, and that there are important test parameters that are left to white papers that operate outside of the Protocols and therefore outside of the stakeholder review process that culminates with ERCOT Board and ultimately PUCT endorsement. The result of this imbalance will be trading off hedgeable congestion costs (the costs of which are returned to loads) for unhedgeable transmission costs. **IPM/Shell –** Shell Energy North America (Shell Energy) supports making prudent investment in transmission projects that are needed to facilitate the build out of substantiated loads. We voted in opposition largely based on our concerns with the lack of transparency and control over the methodology for the incorporation of fictitious generation on the ERCOT system to solve power flow issues with the projected load growth. The methodology used by ERCOT to determine where this generation will be located on the system will have a significant impact on the modeled power flows and the congestion patterns that are used for project evaluation under the congestion cost savings test. This could create congestion cost savings test results that do not produce outcomes consistent with the intent of the methodology. This also raises concerns with the potential for unintended consequences of ERCOT reports containing these congestion patterns impacting the value and certainty of hedging instruments in the forward market. Furthermore, we believe that there is benefit in additional discussion to determine how the gross load cost test can be modified to better reflect the actual net benefits.
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 12/3/24, the ERCOT Board voted unanimously to recommend approval of NPRR1247 as recommended by TAC in the 11/20/24 TAC Report.

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Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1247 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM supports NPRR1247.
ERCOT Opinion	ERCOT supports approval of NPRR1247.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1247 and believes that it provides a positive market impact through regulatory requirements by making the consumer energy cost reduction test the congestion cost savings test in economic project evaluation in response to recent amendments by the PUCT to 16 Texas Administrative Code § 25.101.

Sponsor	
Name	Ping Yan
E-mail Address	Ping.Yan@ercot.com
Company	ERCOT
Phone Number	512-248-4153
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Jordan Troublefield
E-Mail Address	Jordan.Troublefield@ercot.com
Phone Number	512-248-6521

Comments Received	
Comment Author	**Comment Summary**
TIEC 091124	Clarified the time horizon, specified what data the congestion cost savings test measures, and established a requirement for ERCOT to publish data related to its modeling

Board Report

AEPSC 100324	Proposed clarifying language to describe the model and to address the specifics of the production cost savings and congestion cost savings
ROS 100424	Requested PRS continue to table NPRR1247 for further review by PLWG
ERCOT 101124	Responded to the 9/11/24 TIEC and 10/3/24 AEPSC comments with characterization edits; clarified that simulations qualify and assess benefits during the planning horizon with the expectation that benefits continue over the life of a project; requested that congestion cost savings test performance descriptions be relegated to the white paper *Congestion Cost Savings Test Evaluation Guideline*; and expressed concern that the TIEC requirement to "publish all relevant modeling assumptions and outputs" is too broad and vague for ERCOT to reasonably comply with beyond what relevant information is already published via the Market Information System (MIS) Secure Area and on the ERCOT website Planning page
Joint Commenters 101524	Proposed language to clarify how benefits are measured and to codify ERCOT's existing practices for the inclusion of weather scenarios and transmission outage sensitivities in certain economic project evaluations by referencing the white paper *Impact of Weather Uncertainty and Transmission Outages on Economic Project Evaluations* in the Protocols
Reliant 101824	Proposed language to detail how the congestion cost savings test calculation will work, to increase transparency of modeling inputs and outputs, and to provide guardrails to ensure the congestion cost savings test does not produce outcomes inconsistent with the intent of the methodology; also proposed language to utilize PUCT's most recently approved Value of Lost Load (VOLL) in cases where unserved energy cost needs to be incorporated in the congestion cost savings methodology
Joint Commenters 102324	Identified a perceived absence of economic analyses and criteria details in the Planning Guide and proposed codifying ERCOT practices by referencing white papers *Impact of Weather Uncertainty and Transmission Outages on Economic Project Evaluations* and *Congestion Cost Savings Test Evaluation Guideline* in the Protocols until the Protocols and/or Planning Guide are updated in response; and requested that ERCOT provide comments clarifying their interpretation of the language, "If the B/C ratio for the transmission project is within +/- 5% of the economic criteria...", as located in the white paper, *Impact of Weather Uncertainty and Transmission Outages on Economic Project Evaluations*

Board Report

ERCOT 102324	Responded to the 10/18/24 Reliant and 10/23/24 Joint Commenters comments with a request that NPRR1247 not reference VOLL as unserved energy is rarely observed in economic project evaluation; requested that the subject of adding generation or scaling load in planning models be addressed in a separate PGRR; and expressed concern against referencing white papers within the Protocols, citing precedence, best practices, and discretion granted to ERCOT via 16 Texas Administrative Code § 25.101(b)(3)(A)(i) regarding whether to include a project's costs and benefits depending on whether such analysis is appropriate for a specific project
Luminant 102824	Established a stakeholder procedural history of the development of the congestion cost savings test; shared identified concerns; and suggested next steps including a request for more time to review NPRR1247 and related materials ahead of ERCOT's intended use of the test
ERCOT 110124	Expressed intention to assess requirements around adding generation to planning models in a forthcoming PGRR; reiterated its position on excluding white paper references from the Protocols; and committed to previewing any changes to relevant white papers to stakeholders for feedback before changes become effective; urged ROS to adopt NPRR1247 as proposed in the 10/23/24 ERCOT comments
ROS 110824	Endorsed NPRR1247 as amended by the 10/23/24 ERCOT comments
ERCOT 111124	Proposed revising the Revision Description to reference *Impact of Weather Uncertainty and Transmission Outages on Economic Project Evaluations* and *Congestion Cost Savings Test Evaluation Guideline* to further publicize such white papers and promote greater transparency
Luminant 111524	Reiterated concern regarding suboptimal outcomes that might arise from an expedited stakeholder process; proposed ERCOT use a factor of 0.25 to discount benefits that are calculated by the suggested congestion cost savings test; argued that an after-tax weighted average cost of capitol is a more appropriate financing cost than a 2% inflation rate in the economic project evaluation; and expressed caution that the consumer benefits test framework goes beyond the congestion savings policy directive from Senate Bill (SB) 1281 and 16 Texas Administrative Code § 25.101
ERCOT 111924	Responded to the 11/15/24 Luminant comments by citing E3's recommendation of the System-Wide GLC Test as the best option to fit with the rules and structure of the ERCOT market, per their

	Congestion Cost Savings Test for Economic Evaluation of ERCOT Transmission Projects report; argued that the impact of applying a discount factor of 0.25 to the congestion cost savings test is unknown due to insufficient data available to accurately inform a congestion hedging methodology; noted that the inflation rate applied to economic project evaluation is solely used to capture the time value of money when the economic benefits are calculated; and requested that TAC recommend approval of NPRR1247 as amended by the 11/11/24 ERCOT comments
ERCOT 112624	Provided background information to the Reliability and Markets Committee and ERCOT Board leading to the development of NPRR1247, ERCOT's position on NPRR1247, and a summary of stakeholder comments and ERCOT responses

Market Rules Notes

Please note that the following NPRR(s) also propose revisions to Section 3.11.2:

- NPRR1070, Planning Criteria for GTC Exit Solutions

Proposed Protocol Language Revision

3.11.2 Planning Criteria

Commented [JT1]: Please note NPRR1070 also proposes revisions to this section.

(1) ERCOT and Transmission Service Providers (TSPs) shall evaluate the need for transmission system improvements and shall evaluate the relative value of alternative improvements based on established technical and economic criteria.

(2) The technical reliability criteria are established by the Planning Guide, Operating Guides, and the North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT and TSPs shall strongly endeavor to meet these criteria, identify current and future violations thereof and initiate solutions necessary to ensure continual compliance.

(3) ERCOT shall attempt to meet these reliability criteria as economically as possible and shall actively study the need for economic projects to meet this goal.

(4) For economic projects, the net economic benefit of a proposed project, or set of projects, will be assessed over the project's life based on the net ~~societal~~ benefit that is reasonably expected to accrue from the project~~. The project will be recommended if it is reasonably expected to result in positive net societal benefits.~~ as demonstrated through the production cost savings test or the congestion cost savings test.

~~(5)~~ ~~To determine the societal benefit of a proposed project under the production cost savings test, the revenue requirement of the capital cost of the project is compared to the expected savings in system production costs resulting from the project over the expected life of the project. IndirectOther adequately quantifiable and ongoing direct and indirect costs and~~

~~benefits and costs associated with~~to the transmission system attributable to ~~the project should~~may ~~be considered as well, where appropriate.~~ The current set of financial assumptions upon which the revenue requirement calculations for these tests ~~is~~are based will be reviewed annually, updated as necessary by ERCOT, and posted on the Market Information System (MIS) Secure Area. The expected ~~production~~ economic benefits~~costs~~ are based on ~~a~~ chronological simulations of the security-constrained unit commitment and economic dispatch of the generators connected to the ERCOT Transmission Grid to serve the expected ERCOT System Load over the planning horizon, comparing simulations with and without the project. These~~is~~ market simulations are~~is~~ intended to provide a reasonable representation of how the ERCOT System is expected to be operated over the simulated time period. From a practical standpoint, it is not feasible to perform these~~is~~ ~~production cost~~ simulations for the entire 30 to 40 year expected life of the project. Therefore, the ~~production~~ economic benefits~~costs~~ are projected over the period for which ~~a~~ simulations are~~is~~ feasible, which is the planning horizon established in Planning Guide Section 3.1.1.2, Regional Transmission Plan, and a qualitative assessment is made of whether the factors driving the ~~production~~ economic benefits ~~cost savings~~ due to the project can reasonably be expected to continue. ~~If ERCOT must add generation to the planning models that does not satisfy the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, in order to address a supply and demand deficiency, no transmission project can be approved either through the production cost savings test or the congestion cost savings test if the addition of that generation is the primary reason for either economic criterion being met. If so, the levelized ERCOT-wide annual production cost savings over the period for which the simulation is feasible is calculated and compared to the first-year annual revenue requirement of the transmission project. If this production cost savings equals or exceeds this annual revenue requirement for the project, the project is~~~~will be deemed to demonstrate sufficient economic from a societal perspective~~~~benefit and will be recommended.~~

[NPRR1183: Replace paragraph (~~5~~4) above with the following upon system implementation:]

(~~5~~4) For economic projects, the net economic benefit of a proposed project, or set of projects, will be assessed over the project's life based on the net benefit that is reasonably expected to accrue from the project as demonstrated through the production cost savings test or the congestion cost savings test. ~~To determine the societal benefit of a proposed project under the production cost savings test, the revenue requirement of the capital cost of the project is compared to the expected savings in system production costs resulting from the project over the expected life of the project. Indirect~~~~Other adequately quantifiable and ongoing direct and indirect costs and benefits and costs associated with~~~~to the transmission system attributable to the project should~~~~may be considered as well, where appropriate.~~ The current set of financial assumptions upon which the revenue requirement calculations for these tests ~~is~~are based will be reviewed annually, updated as necessary by ERCOT, and posted on the ERCOT website. The expected ~~production~~ economic benefits~~costs~~ are based on ~~a~~ chronological simulations of the security-constrained unit commitment and economic dispatch of the generators connected to the ERCOT Transmission Grid to serve the expected ERCOT System Load over the planning horizon, comparing simulations with and without the project. The~~se~~is market simulations ~~is~~are intended to provide a reasonable representation of how the ERCOT System is expected to be operated over the simulated time period. From a practical standpoint, it is not feasible to perform th~~ese~~is ~~production cost~~ simulations for the entire 30 to 40 year expected life of the project. Therefore, the ~~production~~ economic benefits~~costs~~ are projected over the period for which ~~a~~ simulations ~~is~~are feasible, which is the planning horizon established in Planning Guide Section 3.1.1.2, Regional Transmission Plan, and a qualitative assessment is made of whether the factors driving the ~~production cost savings~~economic benefits due to the project can reasonably be expected to continue. ~~If ERCOT must add generation to the planning models that does not satisfy the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, in order to address a supply and demand deficiency, no transmission project can be approved either through the production cost savings test or the congestion cost savings test if the addition of that generation is the primary reason for either economic criterion being met. If so, the levelized ERCOT-wide annual production cost savings over the period for which the simulation is feasible is calculated and compared to the first year annual revenue requirement of the transmission project. If this production cost savings equals or exceeds this annual revenue requirement for the project, the project iswill be deemed to demonstrate sufficient economic from a societal perspective~~benefit ~~and will be recommended.~~

~~(6) Other indicators based on analyses of ERCOT System operations may be considered as appropriate in the determination of benefits. In order for such an alternate indicator to be considered, the costs must be reasonably expected to be on-going and be adequately quantifiable and unavoidable given the physical limitation of the transmission system. These alternate indicators include:~~

~~(a) Reliability Unit Commitment (RUC) Settlement for unit operations;~~

~~(b) Visible ERCOT market indicators such as clearing prices of Congestion Revenue Rights (CRRs); and~~

~~(c) Actual Locational Marginal Prices (LMPs) and observed congestion.~~

(~~6~~5) To determine the economic benefits of a proposed project under the production cost savings test, the revenue requirement of the capital cost of the project is compared to the expected savings in system production costs resulting from the project over the expected life of the project. Outputs from the market simulations described in paragraph (~~5~~4) above will be used to provide an estimate of the expected reduction in total system-wide production cost due to the project. Other adequately quantifiable and ongoing direct and indirect costs and benefits to the transmission system attributable to the project may be considered as appropriate. If the levelized ERCOT-wide annual production cost savings equals or exceeds the first-year annual revenue requirement of the transmission project, the project will be deemed to demonstrate sufficient economic benefit and will be recommended. ERCOT will publish requested non-confidential modeling inputs, assumptions, and outputs utilized in the production cost savings test if that information can be ~~reasonably~~feasibly provided.

(~~7~~~~6~~6) To determine the economic benefits of a proposed project under the congestion cost savings test, the revenue requirement of the capital cost of the project is compared to the expected system-wide consumer energy cost reduction resulting from the project over the expected life of the project. Outputs from the ~~same~~ market simulations described in paragraph (~~5~~4) above will be used to provide an estimate of the expected reduction in total system-wide consumer energy cost due to the project. In the market simulations, system-wide consumer energy cost will be calculated using hourly load in MWh multiplied by hourly load nodal energy prices in $/MWh. Other adequately quantifiable and ongoing direct and indirect costs and benefits to the transmission system attributable to the project may be considered as appropriate. If the levelized system-wide consumer energy cost reduction equals or exceeds the average of the first three years' annual revenue requirement for the project, the project will be deemed to demonstrate sufficient economic benefit and will be recommended. ~~If ERCOT must incorporate unserved energy cost in the market simulations, modeling, or calculation of the congestion cost savings test, ERCOT will use the most recently approved Value of Lost Load (VOLL) by the Public Utility Commission of Texas (PUCT) to determine the economic value of the unserved energy cost.~~ ERCOT will publish requested non-confidential modeling inputs, assumptions, and outputs utilized in the congestion cost savings test if that information can be ~~reasonably~~feasibly provided.

~~(7) If the "Benefit-to-Cost" ratio (B/C ratio) of a project evaluated under paragraphs (5) and (6) is within 10% of the economic criteria, ERCOT shall perform weather scenario analysis and transmission outage sensitivity analysis to ensure that benefits of a project reflect realistic assumptions and a range of likely conditions as described in a white paper, "Impact of Weather Uncertainty and Transmission Outages on Economic Project Evaluations," posted to the public system planning area of the ERCOT website.~~

ERCOT Impact Analysis Report

NPRR Number	1247	NPRR Title	**Incorporation of Congestion Cost Savings Test in Economic Evaluation of Transmission Projects**
Impact Analysis Date	August 9, 2024		
Estimated Cost/Budgetary Impact	None. Annual Recurring Operations and Maintenance (O&M) Budget Cost: Between $360k and $440k See ERCOT Staffing Impacts		
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)	There will be ongoing operational impacts to the following ERCOT department totaling 2.0 Full-Time Employees (FTEs) to support this NPRR: • Economic Analysis & Long-Term Studies (2.0 FTEs Effort) ERCOT has assessed its ability to absorb the ongoing efforts of this NPRR with current staff and concluded the need for two additional FTEs in the Economic Analysis & Long-Term Studies department. * 3720 hours – to use the new congestion cost saving performance metric to evaluate the economics of transmission projects for both Regional Transmission Plan (RTP) and Long-Term System Assessment (LTSA), and to perform more sensitivity studies by considering the impact of weather year uncertainties and transmission outages. These 2 additional FTEs are included in the ERCOT 2024-2025 approved budget.		
ERCOT Computer System Impacts	ERCOT will update its business processes to implement this NPRR.		
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	<u>1248</u>	**NPRR Title**	**Correction to NPRR1197, Optional Exclusion of Load from Netting at EPS Metering Facilities which Include Resources**
Date of Decision	December 3, 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	11.1.6, ERCOT-Polled Settlement Meter Netting		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) corrects language in Section 11.1.6 which was implemented with the July 1, 2024 Protocols following Public Utility Commission of Texas (PUCT) approval of NPRR1197, Optional Exclusion of Load from Netting at ERCOT-Polled Settlement (EPS) Metering Facilities which Include Resources. The NPRR1197 2/8/24 PRS Report did not correctly reflect the PRS vote "to recommend approval of NPRR1197 as amended by the 2/7/24 Oncor comments as revised by PRS" in paragraph (6) of Section 11.1.6. This error carried through the ensuing 3/27/24 TAC Report and 4/23/24 Board Report, and was approved by the PUCT on 6/13/24. This NPRR aligns the language within Section 11.1.6 with the intended PRS action from February 8, 2024.		
Reason for Revision	☐ <u>Strategic Plan</u> 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	This NPRR corrects a transcription error made by ERCOT within the stakeholder process for NPRR1197 and implements the language as intended by the stakeholders.
PRS Decision	On 9/12/24, PRS voted unanimously to recommend approval of NPRR1248 as submitted. All Market Segments participated in the vote. On 10/17/24, PRS voted unanimously to endorse and forward to TAC the 9/12/24 PRS Report and 8/16/24 Impact Analysis for NPRR1248. All Market Segments participated in the vote.
Summary of PRS Discussion	On 9/12/24, ERCOT Staff provided an overview of NPRR1248. On 10/17/24, there was no discussion.
TAC Decision	On 10/30/24, TAC voted unanimously to recommend approval of NPRR1248 as recommended by PRS in the 10/17/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/30/24, 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 – with the exception of the IMM Opinion which was not available for TAC review.

Board Report

	[X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of NPRR1248 as recommended by TAC in the 10/30/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1248 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 NPRR1248.
ERCOT Opinion	ERCOT supports approval of NPRR1248.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1248 and believes the market impact for NPRR1248 properly aligns Protocol language within Section 11.1.6 with PRS-recommended language inadvertently omitted from NPRR1197 reports.

Sponsor	
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Market Segment	Not applicable

Market Rules Staff Contact	
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Comments Received

Comment Author	Comment Summary
None	

Market Rules Notes

Please note the baseline Protocol language in Section 11.1.6 has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

- NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions (unboxed 9/27/24)
- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources (incorporated 12/1/24)

Proposed Protocol Language Revision

11.1.6 ERCOT-Polled Settlement Meter Netting

(1) As allowed by Section 10, Metering, of these Protocols, ERCOT will perform the approved netting schemes, which sum the meters at a given Generation Resource or Energy Storage Resource (ESR) site.

(2) Both Load consumption and generation production meters will be combined together to obtain a total amount of Load or generation.

(3) For an ESR site with Wholesale Storage Load (WSL):

[NPRR995: Replace paragraph (3) above with the following upon system implementation:]   (3) For an ESR site:

(a) WSL is measured by the corresponding EPS Meter, except that when a Resource Entity for an ESR communicates its auxiliary Load value to the EPS Meter, WSL is calculated by subtracting the auxiliary Load from the total Load measured by the corresponding EPS Meter. If the calculated auxiliary Load is greater than the total Load, WSL shall be zero.

(b) For WSL that is metered behind the POI metering point, the WSL will be added back into the POI metering point to determine the net flows for the POI metering point.

(c) For WSL that is separately metered at the POI, the WSL will not be included in the determination of whether the generation site is net generation or net Load for the purpose of Settlement.

(4) For an ESR that has separately metered its charging Load, but elects not to receive WSL treatment, the Non-WSL ESR Charging Load for the 15-minute interval shall be determined using the metered ESR charging Load.

[NPRR1188: Replace paragraph (4) above with the following upon system implementation:]

(4) For a single POI Generation Resource site that includes an ESR whose charging Load is not receiving WSL treatment or includes a Controllable Load Resource (CLR):

(a) The portion of Non-WSL ESR Charging Load or CLR Load supplied from the grid will be adjusted for Distribution Losses, Transmission Losses, and Unaccounted for Energy (UFE);

(b) The portion of Non-WSL ESR Charging Load or CLR Load supplied from the co-located generation will not be adjusted for Distribution Losses, Transmission Losses, and UFE;

(c) For RTAML, 4-CP, and Load Ratio Share (LRS) volumes, only the Non-WSL ESR Charging Load or CLR Load supplied from the grid (after loss and UFE adjustment) shall be included;

(d) For Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node, (the Non-WSL ESR Charging Load or CLR Load shall be the Load supplied from the grid (after loss and UFE adjustment) plus the Non-WSL ESR Charging Load or CLR Load supplied from the co-located generation;

(e) An Electric Service Identifier (ESI ID) is required for each ESR and CLR and the unadjusted energy supplied from the grid will be allocated to each ESI ID.

(f) For sites with multiple ESRs or CLRs, the unadjusted energy supplied from the grid will be allocated to each ESI ID based upon load ratio share using metered Non-WSL ESR Charging Load or CLR Load or calculated Non-WSL ESR Charging Load; and

(g) For a single POI Generation Resource site that includes an ESR that has separately metered its charging Load, the Non-WSL ESR Charging Load for the 15-minute interval shall be determined using the metered ESR Charging Load.

(5) For an ESR that has not separately metered its charging Load, or has forfeited WSL treatment pursuant to paragraph (3) of Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values, the Non-WSL ESR Charging Load for the 15-minute interval shall be equal to the total metered ESR Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(a) The lesser of the total metered ESR Load or X MWh, where X is calculated as 15% of the ESR's nameplate capacity multiplied by 0.25; or

(b) 15% of the total metered ESR Load for the 15-minute interval.

[NPRR1188: Insert paragraph (6) below upon system implementation and renumber accordingly:]

(6) For a single POI Generation Resource site that includes a CLR, CLR Load shall be metered with an EPS Meter and the metered energy will be considered as Generation Resource production to determine the net flows for Settlement of the corresponding generation site.

[NPRR995: Insert paragraphs (6) and (7) below upon system implementation and renumber accordingly:]

(6) For a Settlement Only Distribution Energy Storage System (SODESS) or Settlement Only Transmission Energy Storage System (SOTESS) that has been approved for WSL treatment and has a single POI or Service Delivery Point:

(a) For withdrawals from the ERCOT System consisting of only WSL or WSL in combination with auxiliary Load:

(i) WSL is measured by the corresponding EPS Meter, except when a Resource Entity communicates its auxiliary Load value to the EPS Meter, WSL is calculated by subtracting the auxiliary Load from the total Load measured by the corresponding EPS Meter. If the calculated auxiliary Load is greater than the total Load, WSL shall be set to zero.

(ii) For measured or calculated WSL that is behind the POI or Service Delivery Point, the WSL will be added back into the POI or Service Delivery Point metering point to determine the net flows for the POI or Service Delivery Point metering point.

(b) For withdrawals from the ERCOT System that include Load other than WSL Load or auxiliary Load:

(i) The charging Load is measured by the corresponding EPS Meter, except that when the Resource Entity communicates its auxiliary Load value to the EPS Meter, the charging Load is calculated by subtracting the auxiliary Load from the total SODESS or SOTESS Load measured by the corresponding EPS Meter. If the calculated auxiliary Load is greater than the total SODESS or SOTESS Load, the charging Load shall be set to zero.

(ii) Where injections are exclusively the result of generation from an SODESS or SOTESS, the WSL quantity shall be determined through the use of a generation accumulator, which is calculated as the accumulated output measured at the POI or Service Delivery Point minus the accumulated charging Load receiving WSL treatment. The charging Load that is less than or equal to the generation accumulator will be settled as WSL for each 15-minute interval.

(iii) Where injections are the result of a combination of SODESS or SOTESS and non-SODESS or non-SOTESS generation, the output channel of the EPS Meter that measures charging Load is required to be used for Settlement. For these sites, the WSL quantity shall be determined through the use of a generation accumulator, which is calculated as the lesser of (i) the accumulated SODESS or SOTESS output or (ii) the accumulated output measured at the POI or Service Delivery Point minus the accumulated charging Load receiving WSL treatment. The charging Load that is less than or equal to the generation accumulator will be settled as WSL for each 15-minute interval.

(iv) For measured or calculated charging Load that is behind the POI or Service Delivery Point, the charging Load will be added back into the POI or Service Delivery Point metering point to determine the net flows for the POI or Service Delivery Point metering point.

(7) For an SODESS or SOTESS that either has not elected or has not been approved for WSL treatment and has a single POI or Service Delivery Point:

(a) For withdrawals from the ERCOT System consisting of only charging Load or charging Load in combination with auxiliary Load, the Non-WSL Settlement Only Charging Load for the 15-minute Settlement Interval shall be determined as follows:

(i) The metered charging Load that would otherwise be eligible for WSL; or

(ii) The total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(A) The lesser of the total metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the ESS multiplied by 0.25; or

(B) 15% of the total SODESS or SOTESS metered Load.

(b) For withdrawals from the ERCOT System that include Load other than Non-WSL Settlement Only Charging Load or auxiliary Load, the Non-WSL Settlement Only Charging Load for the 15-minute Settlement Interval shall be determined as follows:

(i) Where injections are exclusively the result of generation from an SODESS or SOTESS, the Non-WSL Settlement Only Charging Load quantity shall be determined through the use of a generation accumulator, which is calculated as the accumulated output measured at the POI or Service Delivery Point minus the metered or calculated charging Load determined in option (A) or (B) below:

(A) Where the charging Load is separately metered, the accumulated metered charging Load that would otherwise be eligible for WSL; or

(B) Where the charging Load is not separately metered, the accumulated total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(1) The lesser of the total SODESS or SOTESS metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the SODESS or SOTESS multiplied by 0.25; or

(2) 15% of the total SODESS or SOTESS metered Load.

(ii) Where injections are the result of a combination of generation from SODESS or SOTESS and other generating facilities, the output channel of the EPS Meter that measures charging Load is required to be used for Settlement. For these sites, the Non-WSL Settlement Only Charging Load quantity shall be determined through the use of a generation accumulator, which is calculated as the lesser of (a) the accumulated SODESS or SOTESS output or (b) the accumulated output measured at the POI or Service Delivery Point minus:

(A) Where the charging Load is separately metered, the accumulated metered charging Load that would otherwise be eligible for WSL; or

(B) Where the charging Load is not separately metered, the accumulated total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(1) The lesser of the total metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the SODESS or SOTESS multiplied by 0.25; or

(2) 15% of the total SODESS or SOTESS metered Load.

(iii) For each 15-minute interval, the metered or calculated charging Load that is less than or equal to the generation accumulator will be settled as Non-WSL Settlement Only Charging Load.

(6) For a Generation Resource or ESR that excludes its Load(s) from the netting arrangement pursuant to paragraph (9) of Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters:

(a) The excluded~~Non-charging~~ Load(s) are measured by the corresponding EPS Meter, except that when a Resource Entity for an ESR communicates its non-charging Load(s) value(s) to the EPS Meter in accordance with Section 10.2.4~~using approved calculation methods~~.

(b) ~~For non-charging Load(s) that are metered behind the POI metering point, the~~The excluded Load will be added back into the POI metering point to determine the net flows for the POI metering point.

(c) ~~For non-charging Load(s) that are separately metered at the POI, the non-charging Load will not be included in the determination of whether the generation site is net generation or net Load for the purpose of Settlement~~For sites that are not located behind a NOIE meter point, it shall be the responsibility of the TDSP(s) serving the excluded Load at the facility to account for the excluded Load by creating ESI ID(s) and providing ERCOT with interval data. If there is a one-to-one relationship between each excluded Load meter and ESI ID, then the TDSP may request that ERCOT populate the ESI ID(s) for the excluded Load.

ERCOT Impact Analysis Report

NPRR Number	<u>1248</u>	NPRR Title	**Correction to NPRR1197, Optional Exclusion of Load from Netting at EPS Metering Facilities which Include Resources**
Impact Analysis Date		August 16, 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	**1249**	**NPRR Title**	**Publication of Shift Factors for All Active Transmission Constraints in the RTM**
Date of Decision	December 3, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $25k and $45k Project Duration: 3 to 5 months		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2026; Rank – 4740		
Nodal Protocol Sections Requiring Revision	6.5.7.1.13, Data Inputs and Outputs for the Real-Time Sequence and SCED		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) requires ERCOT to publish Shift Factors for all active transmission constraints in the Real-Time Market (RTM), not just the binding transmission constraints.		
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		

Board Report

	☐ 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	Currently, ERCOT calculates Shift Factors for all transmission constraints that are active in the RTM but only publishes Shift Factors for transmission constraints that are binding. The Shift Factors for all active transmission constraints are needed to shadow the Constraint Competitiveness Test (CCT) and the proposed Energy Storage Resource (ESR) mitigation strategy. Enabling Market Participants to shadow all aspects of the market clearing results in a more transparent and efficient market.
PRS Decision	On 9/12/24, PRS voted unanimously to recommend approval of NPRR1249. All Market Segments participated in the vote. On 10/17/24, PRS voted unanimously to endorse and forward to TAC the 9/12/24 PRS Report and 10/15/24 Impact Analysis for NPRR1249 with a recommended priority of 2026 and rank of 4740. All Market Segments participated in the vote.
Summary of PRS Discussion	On 9/12/24, the sponsor reviewed NPRR1249. On 10/17/24, participants reviewed the 10/15/24 Impact Analysis.
TAC Decision	On 10/30/24, TAC voted unanimously to recommend approval of NPRR1249 as recommended by PRS in the 10/17/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/30/24, 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 – with the exception of the IMM Opinion which was not available for TAC review. ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
Board Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of NPRR1249 as recommended by TAC in the 10/30/24 TAC Report.

Board Report

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1249 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The IMM has no opinion on NPRR1249.
ERCOT Opinion	ERCOT supports approval of NPRR1249.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1249 and believes that with the publication of Shift Factors for all active transmission constraints, it provides a positive market impact by improving transparency and efficiency by enabling Market Participants to shadow all aspects of the market clearing results.

Sponsor	
Name	Steve Reedy
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Company	CIM View Consulting LLC
Phone Number	512-937-3048
Cell Number	512-937-30480
Market Segment	Not applicable

Market Rules Staff Contact	
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Phone Number	512-225-7027

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

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

- NPRR1239, Access to Market Information

- Section 6.5.7.1.13
- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
  - Section 6.5.7.1.13
- NPRR1226, Demand Response Monitor
  - Section 6.5.7.1.13

Proposed Protocol Language Revision

6.5.7.1.13 Data Inputs and Outputs for the Real-Time Sequence and SCED

Commented [BA1]: Please note NPRR1226, NPRR1239 and NPRR1246 also propose revisions to this section.

(1) Inputs: The following information must be provided as inputs to the Real-Time Sequence and SCED. ERCOT may require additional information as required, including:

(a) Real-Time data from TSPs including status indication for each point if that data element is stale for more than 20 seconds;

[NPRR857: Replace paragraph (a) 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:]

(a) Real-Time data from TSPs and DCTOs including status indication for each point if that data element is stale for more than 20 seconds;

(i) Transmission Electrical Bus voltages;

(ii) MW and MVAr pairs for all transmission lines, transformers, and reactors;

(iii) Actual breaker and switch status for all modeled devices; and

(iv) Tap position for auto-transformers;

(b) State Estimator results (MW and MVAr pairs and calculated MVA) for all modeled Transmission Elements;

(c) Transmission Element ratings from TSPs;

[NPRR857: Replace paragraph (c) 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:]

(c) Transmission Element ratings from TSPs and DCTOs;

(i) Data from the Network Operations Model:

(A) Transmission lines – Normal, Emergency, and 15-Minute Ratings (MVA); and

(B) Transformers and Auto-transformers – Normal, Emergency, and 15-Minute Ratings (MVA) and tap position limits;

(ii) Data from QSEs:

(A) Generator Step-Up (GSU) transformers tap position;

(B) Resource HSL (from telemetry); and

(C) Resource LSL (from telemetry); and

(d) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element.

[NPRR857: Replace paragraph (d) 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:]

(d) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs, DCTOs, or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element.

(2) ERCOT shall validate the inputs of the Resource Limit Calculator as follows:

(a) The calculated SURAMP and SDRAMP are each greater than or equal to zero; and

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(b) Other provision specified under Section 3.18, Resource Limits in Providing Ancillary Service.

[NPRR1010: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(3) Outputs for ERCOT Operator information and possible action include:

(a) Operator notification of any change in status of any breaker or switch;

(b) Lists of all breakers and switches not in their normal position;

(c) Operator notification of all Transmission Element overloads detected from telemetered or State-Estimated data;

(d) Operator notification of all Transmission Element security violations; and

(e) Operator summary displays:

(i) Transmission system status changes;

(ii) Overloads;

(iii) System security violations; and

(iv) Base Points.

(4) Every hour, ERCOT shall post on the MIS Secure Area the following information:

(a) Status of all breakers and switches used in the NSA except breakers and switches connecting Resources to the ERCOT Transmission Grid;

(b) All binding transmission constraints and the contingency or overloaded element pairs that caused such constraint; and

(c) Shift Factors for all active transmission constraints, including Private Use Network Settlement Points, by Resource Node, Hub, Load Zone, and DC Tie.

(5) Sixty days after the applicable Operating Day, ERCOT shall post on the MIS Secure Area, the following information:

(a) Hourly transmission line flows and voltages from the State Estimator, excluding transmission line flows and voltages for Private Use Networks; and

(b) Hourly transformer flows, voltages and tap positions from the State Estimator, excluding transformer flows, voltages, and tap positions for Private Use Networks.

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(6) Notwithstanding paragraph (5) above, ERCOT, in its sole discretion, shall release relevant State Estimator data less than 60 days after the Operating Day if it determines the release is necessary to provide complete and timely explanation and analysis of unexpected market operations and results or system events including, but not limited to, pricing anomalies, recurring transmission congestion, and system disturbances. ERCOT's release of data under this paragraph shall be limited to intervals associated with the unexpected market or system event as determined by ERCOT. The data release shall be made available simultaneously to all Market Participants.

(7) Every hour, ERCOT shall post on the ERCOT website, the sum of ERCOT generation, and flow on the DC Ties, all from the State Estimator.

(8) After every SCED run, ERCOT shall post to the ERCOT website the sum of the HDL and the sum of the LDL for all Generation Resources On-Line and Dispatched by SCED.

(9) Sixty days after the applicable Operating Day, ERCOT shall post to the ERCOT website the summary LDL and HDL report from paragraph (8) above and include instances of manual overrides of HDL or LDL, including the name of the Generation Resource and the type of override.

(10) No sooner than sixty days after the applicable Operating Day, ERCOT shall provide to the appropriate Technical Advisory Committee (TAC) subcommittee instances of manual overrides of HDL or LDL, including the name of the Generation Resource, the reason for the override, and, as applicable, the cost as calculated in Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment.

(11) After every SCED run, ERCOT shall post to the MIS Certified Area, for any QSE, instances of a manual override of the HDL or LDL for a Generation Resource, including the original and overridden HDL or LDL.

ERCOT Impact Analysis Report

NPRR Number	**1249**	**NPRR Title**	**Publication of Shift Factors for All Active Transmission Constraints in the RTM**
Impact Analysis Date	October 15, 2024		
Estimated Cost/Budgetary Impact	Between $25k and $45k		
Estimated Time Requirements	The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 3 to 5 months		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: Data and Information Products 76% Market Management System 24%		
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	1254	NPRR Title	Modeling Deadline for Initial Submission of Resource Registration Data
Date of Decision	December 3, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: Not applicable		
Proposed Effective Date	March 1, 2025		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	3.10.1, Time Line for Network Operations Model Changes		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) requires Resource Entities to submit the initial Resource Registration data for a Generator Interconnection or Modification (GIM) project, required by paragraph (6) of Planning Guide Section 6.8.1, Resource Registration, four months prior to target inclusion in the ERCOT Network Operations Model. This provides a one-month period for ERCOT and the Resource Entities to address errors or deficiencies consistent with the process outlined in Planning Guide Section 6.8.2, Resource Registration Process.		
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		

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	[X] 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	The current time line for Network Operations Model changes as defined in Section 3.10.1 does not provide ERCOT sufficient time to process many of the initial Resource Registration data submissions for new GIM requests. These submissions consist of voluminous and complicated data that often require discussion with the submitter to correct errors or deficiencies before ERCOT modeling work can commence. ERCOT has been receiving a growing number of these submissions 1-2 days before the current deadline in paragraph (3) of Section 3.10.1. These last-minute submissions do not leave enough time to resolve errors or deficiencies before modeling work begins. Yet, ERCOT is bound by the Protocols to model the data, even if it is of poor quality. Additionally, Resource Entities' submission of registration data on the deadline has presented issues for Transmission and/or Distribution Service Providers' (TDSPs') submitting Network Operations Model Change Requests (NOMCRs) to update transmission equipment that is related to the new Resource Entity station. Requiring Resource Entities to submit initial Resource Registration data one month prior to the current three-month modeling deadline will provide ERCOT adequate time to review the data and address modeling deficiencies and errors. This deadline has previously been a recommendation in the Resource Interconnection Handbook; however, it has not reduced the volume of last-minute submissions. Therefore, ERCOT is formalizing this requirement in the Protocols to ensure adequate time for modeling of equipment and to align with Planning Guide Section 6.8, Resource Registration Procedures.
PRS Decision	On 10/17/24, PRS voted unanimously to recommend approval of NPRR1254 as submitted. All Market Segments participated in the vote. On 11/14/24, PRS voted unanimously to endorse and forward to TAC the 10/17/24 PRS Report and 10/2/24 Impact Analysis for NPRR1254. All Market Segments participated in the vote.
Summary of PRS Discussion	On 10/17/24, ERCOT Staff provided an overview of NPRR1254.

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	On 11/14/24, participants reviewed the 10/2/24 Impact Analysis for NPRR1254.
TAC Decision	On 11/20/24, TAC voted unanimously to recommend approval of NPRR1254 as recommended by PRS in the 11/14/24 PRS Report with a recommended effective date of March 1, 2025. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/20/24, ERCOT clarified it was amendable to a March 1, 2025 effective date for NPRR1254.
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 12/3/24, the ERCOT Board voted unanimously to recommend approval of NPRR1254 as recommended by TAC in the 11/20/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1254 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 NPRR1254.
ERCOT Opinion	ERCOT supports approval of NPRR1254.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1254 and believes the market impact of adjusting the timeline for submitting the initial Resource Registration data for GIM projects will have a positive market impact by providing a one-month period for ERCOT and Resource Entities to address errors or deficiencies resulting in improved coordination.

Sponsor	
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E-mail Address	agee.springer@ercot.com

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Company	ERCOT
Phone Number	512-248-4508
Cell Number	None
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
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Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

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

- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
    - Section 3.10.1

Proposed Protocol Language Revision

3.10.1 Time Line for Network Operations Model Changes

Commented [EWG1]: Please note NPRR1246 also proposes revisions to this section.

(1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

[NPRR857: Replace paragraph (1) 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:]

(1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs, DCTOs, and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

(2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource or Settlement Only Generator (SOG) as described in Planning Guide Section 5, Generator Interconnection or Modification, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource or SOG.

[NPRR995: Replace paragraph (2) above with the following upon system implementation:]

(2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource, Settlement Only Generator (SOG), or Settlement Only Energy Storage System (SOESS) as described in Planning Guide Section 5, Generator Interconnection or Modification, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource, SOG, or SOESS.

(3) TSPs and Resource Entities shall submit all Network Operations Model updates that are not subject to the requirements of paragraph (4) below by the applicable deadline to submit information to ERCOT for the target date of inclusion in the production model detailed in the table below. ERCOT shall update the Network Operations Model according to the following table:

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Deadline to Submit Information to ERCOT Note 1	Model Complete and Available for Test Note 2	Updated Network Operations Model Testing Complete Note 3 Paragraph (6~~5~~)	Update Network Operations Model Production Environment	Target Physical Equipment included in Production Model Note 4
Jan 1	Feb 15	March 15	April 1	Month of April
Feb 1	March 15	April 15	May 1	Month of May
March 1	April 15	May 15	June 1	Month of June
April 1	May 15	June 15	July 1	Month of July
May 1	June 15	July 15	August 1	Month of August
June 1	July 15	August 15	September 1	Month of September
July 1	August 15	September 15	October 1	Month of October
August 1	September 15	October 15	November 1	Month of November
September 1	October 15	November 15	December 1	Month of December
October 1	November 15	December 15	January 1	Month of January (the next year)
November 1	December 15	January 15	February 1	Month of February (the next year)
December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. TSP and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.
2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4. ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.
4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

[NPRR857: Replace paragraph (3) 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

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interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) TSPs, DCTOs, and Resource Entities shall submit all Network Operations Model updates that are not subject to the requirements of paragraph (4) below by the applicable deadline to submit information to ERCOT for the target date of inclusion in the production model detailed in the table below. ERCOT shall update the Network Operations Model according to the following table:

Deadline to Submit Information to ERCOT **Note 1**	**Model Complete and Available for Test** **Note 2**	**Updated Network Operations Model Testing Complete** **Note 3** **Paragraph (65)**	**Update Network Operations Model Production Environment**	**Target Physical Equipment included in Production Model** **Note 4**
Jan. 1	Feb 15	March 15	April 1	Month of April
Feb 1	March 15	April 15	May 1	Month of May
March 1	April 15	May 15	June 1	Month of June
April 1	May 15	June 15	July 1	Month of July
May 1	June 15	July 15	August 1	Month of August
June 1	July 15	August 15	September 1	Month of September
July 1	August 15	September 15	October 1	Month of October
August 1	September 15	October 15	November 1	Month of November
September 1	October 15	November 15	December 1	Month of December
October 1	November 15	December 15	January 1	Month of January (the next year)
November 1	December 15	January 15	February 1	Month of February (the next year)
December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. TSP, DCTO, and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.
2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4. for market review and further testing by Market Participants.
3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.

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4.	Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

(4) Resource Entities shall submit complete initial Resource Registration data for inclusion in the ERCOT Network Operations Model as described in paragraph (6) of Planning Guide Section 6.8.1, Resource Registration, by the applicable deadline for the Resource Entity to submit complete information to ERCOT for the target date of inclusion in the production model detailed in the table below. ERCOT shall update the Network Operations Model according to the following table:

Deadline for Resource Entity to Submit Complete Information to ERCOT **Note 1**	**Deadline for Resource Registration Data to Meet Criteria for ERCOT Acceptance** **Note 2**	**Model Complete and Available for Test** **Note 3**	**Updated Network Operations Model Testing Complete** **Note 4** **Paragraph (6)**	**Update Network Operations Model Production Environment**	**Target Physical Equipment included in Production Model** **Note 5**
December 1	January 1	February 15	March 15	April 1	Month of April
January 1	February 1	March 15	April 15	May 1	Month of May
February 1	March 1	April 15	May 15	June 1	Month of June
March 1	April 1	May 15	June 15	July 1	Month of July
April 1	May 1	June 15	July 15	August 1	Month of August
May 1	June 1	July 15	August 15	September 1	Month of September
June 1	July 1	August 15	September 15	October 1	Month of October
July 1	August 1	September 15	October 15	November 1	Month of November
August 1	September 1	October 15	November 15	December 1	Month of December
September 1	October 1	November 15	December 15	January 1	Month of January (the next year)
October 1	November 1	December 15	January 15	February 1	Month of February (the next year)
November 1	December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. The date listed in this column shall serve as the deadline for initial submission of complete Resource Registration data to ERCOT, as described in paragraph (2) of Planning Guide Section 6.8.2, Resource Registration Process. ERCOT may work with the Resource Entity to resolve any data quality issues found in the Resource Registration

data for up to one month after the submission date that corresponds to the date listed in this column. If ERCOT determines any Resource Registration data deficiencies are not sufficiently resolved by the end of the one-month period, then that submission shall be treated as a new initial submission for the following month.

2. Resource Entity data submission must be deemed complete by ERCOT with all data deficiencies resolved per the process described in Planning Guide Section 6.8.2 by this date.
3. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
4. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the EMS testing prior to placing the new model into the production environment.
5. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

(~~4~~5) ERCOT shall only approve energization requests when the Transmission Element is satisfactorily modeled in the Network Operations Model.

(~~5~~6) Changes to an existing NOMCR that modify only Inter-Control Center Communications Protocol (ICCP) data object names shall be provided 15 days prior to the Network Operations Model load date. NOMCR modifications containing only ICCP data object names shall not be subject to interim update reporting to the Independent Market Monitor (IMM) and Public Utility Commission of Texas (PUCT) (reference Section 3.10.4), according to the following:

NOMCR that contains ICCP Data and is submitted …	*ERCOT shall …*	*Subject to IMM & PUC Reporting*
Beyond 90 days of the energization date	Allow modification of only ICCP data for an existing NOMCR	No
Between 90 and 15 days prior to the scheduled database load.	Allow modification of only ICCP data for an existing NOMCR	No
Less than 15 days before scheduled database load.	Require a new NOMCR to be submitted containing the ICCP data	Yes

ERCOT Impact Analysis Report

NPRR Number	1254	NPRR Title	Modeling Deadline for Initial Submission of Resource Registration Data
Impact Analysis Date	October 2, 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	266	**NOGRR Title**	**Related to NPRR1239, Access to Market Information**
Date of Decision	December 3, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: Not applicable		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1239, Access to Market Information		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	9.3.2, System and Resource Control		
Related Documents Requiring Revision/Related Revision Requests	NPRR1239		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) moves from the Market Information System (MIS) Secure Area to the public ERCOT website reports that do not contain ERCOT Critical Energy Infrastructure Information (ECEII). ERCOT Staff analyzed reports in the MIS Secure Area, along with existing Protocols for posting requirements, and identified no ongoing basis for holding in the MIS Secure Area reports determined to contain only information for a market audience and not ECEII.		
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		

Board Report

	☒ 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	Reports that are not Protected Information in the MIS Secure Area are available to any registered Market Participant who requests a standard Digital Certificate from ERCOT, and paragraph (1)(j) of Protocol Section 1.3.1.2, Items Not Considered Protected Information, treats similarly requirements to post non-Protected Information on the ERCOT website or on the MIS Secure Area. This Revision Request moves reports that are not ECEII from the MIS Secure Area to the ERCOT website so the public can directly access reports that are not Protected Information without registering as a Market Participant and requesting ERCOT to issue a Digital Certificate, or without submitting an ERCOT Information Request.
ROS Decision	On 8/1/24, ROS voted unanimously to table NOGRR266. All Market Segments participated in the vote. On 9/9/24, ROS voted unanimously to recommend approval of NOGRR266 as submitted. All Market Segments participated in the vote. On 10/3/24, ROS voted unanimously to endorse and forward to TAC the 9/9/24 ROS Report and 7/2/24 Impact Analysis for NOGRR266. All Market Segments participated in the vote.
Summary of ROS Discussion	On 8/1/24, ERCOT Staff presented NOGRR266. Participants requested additional time to review. ERCOT Staff requested interested parties file comments regarding specific concerns. On 9/9/24, there was no discussion. On 10/3/24, participants reviewed the 7/2/24 Impact Analysis.
TAC Decision	On 10/30/24, TAC voted unanimously to table NOGRR266. All Market Segments participated in the vote. On 11/20/24, TAC voted unanimously to recommend approval of NOGRR266 as recommended by ROS in the 10/3/24 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/30/24, there was no additional discussion beyond TAC review of the items below.

Board Report

	On 11/20/24, there was no discussion.
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 Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of NOGRR266 as recommended by TAC in the 11/20/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR266.
ERCOT Opinion	ERCOT supports approval of NOGRR266.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR266 and believes it provides a positive market impact by improving access and transparency by moving reports that are not ECEII from the MIS Secure Area to the ERCOT website so the public can directly access reports without registering as a Market Participant and requesting ERCOT to issue a Digital Certificate, or without submitting an ERCOT Information Request.

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Market Segment	Not Applicable

Board Report

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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

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

- NOGRR268, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
  - Section 9.3.2

Proposed Guide Language Revision

9.3.2 System and Resource Control

Commented [BA1]: Please note NOGRR268 also proposes revisions to this section.

(1) The following reports shall be posted on the ~~MIS Secure Area~~ERCOT website:

(a) Resource control metrics:

(i) Total Regulation Up Service (Reg-Up) and Regulation Down Service (Reg-Down) per interval - ERCOT shall develop a monthly report detailing the total amount of Reg-Up energy deployed in the Settlement Interval and by hour and the total amount of Reg-Down energy deployed for each Settlement Interval and by hour of the Operating Day.

(b) Reliability Unit Commitments (RUCs) and deployments:

(i) For each month, ERCOT shall report, Generation Resources committed in each RUC process, the reason for the commitment, Resource name and intervals deployed, and the hours committed for Voltage Support Service (VSS).

(c) Reversal of Base Point instructions to Generation Resources from interval to interval:

Board Report

(i) ERCOT shall record and report, on a monthly basis, instances of Dispatch Instructions to Resources not providing Regulation Service in which there is a directional change in Base Point instructions for four consecutive Security-Constrained Economic Dispatch (SCED) intervals for validation and review.

ERCOT Impact Analysis Report

NOGRR Number	266	NOGRR Title	Related to NPRR1239, Access to Market Information
Impact Analysis Date	July 2, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1239, Access to Market Information.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1239.

Board Report

NOGRR Number	**267**	**NOGRR Title**	**Related to NPRR1240, Access to Transmission Planning Information**
Date of Decision	December 3, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: Not applicable		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1240, Access to Transmission Planning Information		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	9.2.3, Transmission Outage Reporting 9.3.1, Transmission Control		
Related Documents Requiring Revision/Related Revision Requests	NPRR1240 Planning Guide Revision Request (PGRR) 116, Related to NPRR1240, Access to Transmission Planning Information		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) moves from the Market Information System (MIS) Secure Area to the public ERCOT website reports that do not contain ERCOT Critical Energy Infrastructure Information (ECEII). ERCOT Staff analyzed reports in the MIS Secure Area, along with existing Protocols for posting requirements, and identified no ongoing basis for holding in the MIS Secure Area reports determined to contain only Transmission planning information for a market audience, consisting of percentages of Transmission Outage totals by scheduling and type, and monthly reports that show the rates at which solutions converged in the State Estimator application and not ECEII.		
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		

Board Report

	☐ 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	Reports that are not Protected Information in the MIS Secure Area are available to any registered Market Participant who requests a standard Digital Certificate from ERCOT, and paragraph (1)(j) of Protocol Section 1.3.1.2, Items Not Considered Protected Information, treats similarly requirements to post non-Protected Information on the ERCOT website or on the MIS Secure Area. This Revision Request moves reports that are not ECEII from the MIS Secure Area to the ERCOT website so the public can directly access reports that are not Protected Information without registering as a Market Participant and requesting ERCOT to issue a Digital Certificate, or without submitting an ERCOT Information Request.
ROS Decision	On 8/1/24, ROS voted unanimously to table NOGRR267. All Market Segments participated in the vote. On 9/9/24, ROS voted unanimously to recommend approval of NOGRR267 as submitted. All Market Segments participated in the vote. On 10/3/24, ROS voted unanimously to endorse and forward to TAC the 9/9/24 ROS Report and 7/2/24 Impact Analysis for NOGRR267. All Market Segments participated in the vote.
Summary of ROS Discussion	On 8/1/24, ERCOT Staff presented NOGRR267. Participants requested additional time to review. ERCOT Staff requested interested parties file comments regarding specific concerns. On 9/9/24, there was no discussion. On 10/3/24, participants reviewed the 7/2/24 Impact Analysis.
TAC Decision	On 10/30/24, TAC voted unanimously to table NOGRR267. All Market Segments participated in the vote.

Board Report

	On 11/20/24, TAC voted unanimously to recommend approval of NOGRR267 as recommended by ROS in the 10/3/24 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/30/24, there was no additional discussion beyond TAC review of the items below. On 11/20/24, there was no discussion.
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)
Board Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of NOGRR267 as recommended by TAC in the 11/20/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR267.
ERCOT Opinion	ERCOT supports approval of NOGRR267.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR267 and believes it provides a positive market impact by improving access and transparency by moving reports that are not ECEII from the MIS Secure Area to the ERCOT website so the public can directly access reports without registering as a Market Participant and requesting ERCOT to issue a Digital Certificate, or without submitting an ERCOT Information Request.

Sponsor	
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Board Report

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Market Segment	Not Applicable

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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Protocol Language Revision

9.2.3 Transmission Outage Reporting

(1) This Section describes the reporting data for the transmission Outage scheduling and is provided for informational purposes. There are no performance metrics for this data.

(2) ERCOT shall post a monthly report of Outages considered on the MIS Secure Area including:

(a) Number of Outage requests submitted in the ERCOT Outage Scheduler greater than 335 days (11 months) in advance;

(b) Number of Outage requests submitted in the ERCOT Outage Scheduler between 90 and 334 days in advance of the desired Outage date;

(c) Number of Outage requests submitted in the ERCOT Outage Scheduler between eight and 89 days in advance of the desired Outage date;

(d) Number of Outage requests submitted in the ERCOT Outage Scheduler between three and seven days in advance of the desired Outage date;

(e) Number of Outage requests submitted less than three days in advance;

(f) Number of Outages by Outage type; and

(g) Total Number of Outages that were requested, accepted, approved, cancelled, and withdrawn.

(3) ERCOT shall post on the ERCOT website reports for each transmission owner showing the percentage of the total number of Outages, by type, described in paragraph (2) above.

9.3.1 Transmission Control

(1) ERCOT shall report State Estimator performance in accordance with the Protocols and post such report on the Market Information System (MIS) Secure Area, except where otherwise stated in this Section 9.3.1 (1).

(a) ERCOT shall ~~produce~~ post on the ERCOT website monthly reports describing State Estimator convergence and valid State Estimator solution rates as described in Protocol Section 3.10.9.6, Telemetry and State Estimator Performance Monitoring.

(b) ERCOT shall produce monthly reports describing the MW differences between State Estimator results and power flow results for identified congested Transmission Elements as approved by the Technical Advisory Committee (TAC).

(c) ERCOT shall produce monthly reports describing the MW differences between the State Estimator results and telemetry for identified congested Transmission Elements as approved by TAC.

(d) ERCOT shall produce monthly reports describing the voltage differences between the State Estimator results and telemetry for the most important voltage busses identified in accordance with the Protocols.

(e) ERCOT shall produce monthly reports describing the MW differences as defined in the Protocols.

(f) ERCOT shall produce monthly reports identifying the sum of MW flows around telemetered State Estimator Busses as described in paragraph (5) of Protocol Section 3.10.7.5.2, Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows.

ERCOT Impact Analysis Report

NOGRR Number	**<u>267</u>**	**NOGRR Title**	**Related to NPRR1240, Access to Transmission Planning Information**
Impact Analysis Date	July 2, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1240, Access to Transmission Planning Information.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1240.

Board Report

OBDRR Number	**<u>053</u>**	**OBDRR Title**	**Alignment with NPRR1131, Controllable Load Resource Participation in Non-Spin, and Minor Clean-Ups**
Date of Decision	December 3, 2024		
Action	Recommended Approval		
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		
Other Binding Document Requiring Revision	Non-Spinning Reserve Deployment and Recall Procedure		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Other Binding Document Revision Request (OBDRR) aligns the Non-Spinning Reserve Deployment and Recall Procedure with revisions from Nodal Protocol Revision Request (NPRR) 1131, Controllable Load Resource Participation in Non-Spin, along with other minor clean-ups.		
Reason for Revision	☐ <u>Strategic Plan</u> Objective 1 – Be an industry leader for grid reliability and resilience ☐ <u>Strategic Plan</u> Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ <u>Strategic Plan</u> 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	This OBDRR maintains alignment between this Other Binding Document and the Protocols.
TAC Decision	On 10/30/24, TAC voted unanimously to recommend approval of OBDRR053 as submitted and the 10/17/24 Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/30/24, 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 – with the exception of the IMM Opinion which was not available for TAC review. ☒ Comments were reviewed and discussed ☐ Other: (explain)
ERCOT Board Decision	On 12/3/24, the ERCOT Board voted unanimously to recommend approval of OBDRR053 as recommended by TAC in the 10/30/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion for OBDRR053.
ERCOT Opinion	ERCOT supports approval of OBDRR053.
ERCOT Market Impact Statement	ERCOT Staff has reviewed OBDRR053 and believes the market impact for OBDRR053 maintains alignment between this Other Binding Document and the Protocols.

Sponsor

Board Report

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Market Segment	Not applicable

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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Other Binding Document Language Revision

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

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

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

In each of these cases, the ERCOT operator will make the final decision and initiate the deployment. The ERCOT operator shall deploy Non-Spin in amounts sufficient to respond to the operational circumstances. This means that Non-Spin may be deployed partially over time or may be deployed in its entirety. If Non-Spin is deployed partially, it shall be deployed in increments of 100% of each Resource's capacity. ~~To support partial deployment, ERCOT shall, following the Day-Ahead Market (DAM), rank, for each hour of the Operating Day, the Resources supplying Non-Spin in an economic order based on DAM Settlement Point Prices. Partial Non-Spin deployment and recall decisions shall be based on each Resource's economic cost order. When deploying Non-Spin, the Load Resources that are not Controllable Load Resources will be deployed after other Non-Spin from Off-Line Generation Resources.~~

2. Non-Spin Deployment

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

- When (High Ancillary Service Limit (HASL) – Gen – Intermittent Renewable Resource (IRR) Curtailment) – (30-minute net load ramp) < 0 MW, deploy sufficient Non-Spin capacity so that (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) > 500 MW.
- When Physical Responsive Capability (PRC) < 3200 MW and not expected to recover within 30 minutes without deploying reserves, deploy all or a portion of the available Non-Spin capacity.
- When PRC < 2500 MW, deploy all of the available Non-Spin capacity.
- When the North-to-Houston (N_H) Voltage Stability Limit Reliability Margin < 300 MW, deploy Non-Spin (all or partial) in the Houston area as needed to restore reliability margin.
- When Off-Line Generation Resources providing Non-Spin are the only reasonable option available to the Operator for resolving local issues, deploy available Non-Spin capacity on only the necessary individual Resources.
- Load Resources that are not Controllable Load Resources and Generation Resources providing Off-Line Non-Spin will be separated into deployment groups as defined in Nodal Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.
- Load Resources that are not Controllable Load Resources and Generation Resources providing Off-Line Non-Spin can be deployed individually, in groups, or as an entire block providing Non-Spin. Deployments that do not encompass an entire block may only be done to manage inertia, congestion, or for other local needs.

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

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

2.1 Off-Line Generation Resource reserved for Non-Spin

- The Qualified Scheduling Entity (QSE) will be sent a Resource-specific Dispatch Instruction deployment indicating a time and date stamp, QSE, Dispatch Asset Code, and Deployed MW.
- The Dispatch Instruction for an Off-Line Generation Resource must include the expected amount of *capacity* that will be available for SCED and the anticipated duration of the deployment.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that Off-Line Generation Resource has been reduced to zero within 20 minutes of the Dispatch Instruction.
- The QSE must have the Off-Line Generation Resource On-Line with an Energy Offer Curve and the telemetered net generation must be greater than or equal to the Resource's telemetered Low Sustained Limit (LSL) multiplied by P1 where P1 is defined in the "ERCOT and QSE Operations Business Practices During the Operating Hour" within 25 minutes of the Dispatch Instruction.
- SCED will respond to the changes in Resource Status that are received by telemetry from the QSE.
- Once the Resource is On-Line it is Dispatched as any other Generation Resource including any provisions for processing generation less than the Resource's LSL.
- The Resource must, at a minimum, be capable of providing all the Non-Spin energy to SCED within 30 minutes of the Dispatch Instruction.
- The Load Resource must, at a minimum, be capable of remaining deployed until recalled.

2.2 On-Line Generation Resource with an Energy Offer Curve

- For a Resource that *will not use power augmentation* to provide any portion of its Non-Spin Ancillary Service Resource Responsibility:
  - The QSE shall set the value of the Non-Spin Ancillary Service Schedule to zero within the 30-second window prior to the start of the delivery hour.
  - ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
  - The total amount of capacity reserved on that Resource for Non-Spin shall be considered as a standing Non-Spin deployment Dispatch Instruction for the duration of the Operating Hour.
  - A Non-Spin deployment Dispatch Instruction from ERCOT is not required for standing Non-Spin deployments.

- For a Resource that *will use power augmentation* to provide a specific MW portion of its Non-Spin Ancillary Service Responsibility:
    - The QSE shall set the value of the Non-Spin Ancillary Service Schedule to the appropriate value within the 30-second window prior to the start of the delivery hour.
    - The QSE may set the value of the Non-Spin Ancillary Service Schedule equal to the MW amount of Non-Spin that will be provided via power. augmentation; otherwise, the QSE may set the value of the schedule to zero.
    - If the Non-Spin Ancillary Service Schedule is set to zero, then the total amount of capacity reserved on that Resource for Non-Spin shall be considered as a standing Non-Spin deployment Dispatch Instruction for the duration of the Operating Hour.
    - If the Non-Spin Ancillary Service Schedule is set to a non-zero value, then the QSE will be sent a Resource-specific Dispatch Instruction indicating that Non-Spin has been deployed for the total amount of the Non-Spin Schedule.
        - The Dispatch Instruction must include the expected amount of *capacity* that will be available for SCED and the anticipated duration of the deployment.
        - The QSE shall reduce the Resource's Non-Spin Ancillary Service Schedule to zero within 20 minutes following a deployment instruction.
    - ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- The QSE must, at a minimum, ensure that the Normal Ramp Rate represented by the Resource's ramp rate curve is sufficient to allow SCED to fully Dispatch the Resource's Non-Spin Resource Responsibility within 30 minutes, regardless of whether or not the Resource uses power augmentation to provide the service.

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

- The QSE shall set the value of the Non-Spin Ancillary Service Schedule to zero within the 30-second window prior to the start of the delivery hour.
- ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- If the QSE is sent a Resource-specific Dispatch Instruction indicating that Non-Spin has been deployed:
    - The Dispatch Instruction must include the additional amount of *energy* (MW) that needs to be produced by the Resource and the estimated duration of the deployment.
    - For Dynamically Scheduled Resources (DSRs) providing Non-Spin, as soon as the QSE receives the deployment, the QSE shall adjust the telemetry

Output Schedule to reflect the Non-Spin deployment. A DSR QSE with a Load Resource that has provided Non-Spin will ensure that the Output Schedule is not reduced to reflect the Load deployment if the Load Resource is part of the DSR Load that the Resource follows.

- For non-DSRs (with Output Schedules) providing Non-Spin, ERCOT shall increase the Output Schedule used in SCED by the difference between telemetered Non-Spin Ancillary Service Resource Responsibility and Ancillary Service Schedule to reflect the amount of Non-Spin energy that is to be provided by the Resource in response to the Non-Spin deployment.

2.4 Controllable Load Resource with Non-Spin Ancillary Service Resource Responsibility

- The QSE shall set the value of the Non-Spin Ancillary Service Schedule to zero within the 30-second window prior to the start of the delivery hour.
- ERCOT will automatically calculate new Low Ancillary Service Limit (LASL) constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- The total amount of capacity reserved on that Resource for Non-Spin shall be considered as a standing Non-Spin deployment Dispatch Instruction for the duration of the Operating Hour.
- A Non-Spin deployment Dispatch Instruction from ERCOT is not required for standing Non-Spin deployments.
- ~~The QSE will be sent a Resource-specific Dispatch Instruction that Non-Spin has been deployed.~~
- ~~The Dispatch Instruction must include the expected amount of capacity that will be available for SCED and the anticipated duration of the deployment.~~
- ~~The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that Controllable Load Resource has been reduced to zero within 20 minutes of the Dispatch Instruction.~~
- The QSE must have the Controllable Load Resource's telemetered Resource Status as On-Line (ONRGL and/or ONCLR, whichever is applicable) with an RTM Energy Bid per paragraph (1)(b) of Protocol Section 6.4.4.1, Energy Offer Curve or Energy Bid Curve for On-Line Non-Spinning Reserve Capacity, and the Controllable Load Resource's telemetered net real power consumption must be greater than or equal to the Controllable Load Resource's telemetered LPC plus its total upward Ancillary Service Resource Responsibility.
- ~~ERCOT will automatically calculate new LASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.~~
- ~~Once the Controllable Load Resource's Non-Spin capacity has been released to SCED, this capacity is Dispatched as any other Resource available to SCED.~~

- ~~The Controllable Load Resource must, at a minimum, be capable of providing all the Non-Spin energy to SCED within 30 minutes of the Dispatch Instruction.~~

2.5 Load Resource that is not a Controllable Load Resource with Non-Spin Ancillary Service Resource Responsibility

- The QSE must show the Load Resource's telemetered Resource Status as On-Line (ONRL) and, if equipped with an under-frequency relay, the relay should not be armed and the status should indicate Disabled.
- Load Resources that are not Controllable Load Resources and Generation Resources providing offline Non-Spin will be separated into deployment groups as defined in Nodal Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.
- The QSE will be sent a Resource-specific Dispatch Instruction for the Non-Spin deployment indicating a time and date stamp, QSE, Dispatch Asset Code, and Deployed MW.
- The Dispatch Instruction must include the expected amount of capacity that will be expected to be dropped by the Load Resource within 30 minutes.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that Load Resource has been reduced to zero within one minute of receiving the Dispatch Instruction.
- The Load Resource must, at a minimum, be capable of remaining deployed until recalled.

3. Recall of Non-Spin Deployment

The deployed Non-Spin may be recalled in a manner that is expected to maintain (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) > 1000 MW and PRC is > 3200 MW. Non-Spin provided by Off-Line Generation Resources and Load Resources that are not Controllable Load Resources will be recalled first, followed by Controllable Load Resources and On-Line Generation Resources until all the Non-Spin is recalled. Non-Spin block deployments shall be recalled in the reverse order in which they were deployed or may be recalled all at once, at ERCOT's discretion.

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

- After recall, the QSE for a Generation Resource will be allowed to use normal shutdown procedures to take the Generation Resource Off-Line if the QSE wants to shut down the Resource. In this case, the Non-Spin Ancillary Service Schedule for that Generation Resource will be reset to equal the Non-Spin Ancillary Service Responsibility for that Generation Resource for that hour. A QSE with a Generation Resource that was previously Off-Line will be allowed to keep the Generation Resource On-Line after the minimum On-Line time, provided that the difference between its High Sustained Limit (HSL) and LSL is greater than or equal to its Ancillary Service Resource Responsibility.
- A QSE with a Generation Resource (with an Energy Offer Curve) that will stay On-Line may set the value of the Non-Spin Ancillary Service Schedule equal to the MW amount

of Non-Spin that will be provided via power augmentation; otherwise, the QSE will ensure that the value of the Non-Spin Ancillary Service Schedule for that Resource is set to 0 MW.

- A QSE with a DSR Generation Resource (with an Output Schedule) that will stay On-Line will back out the Non-Spin addition that was made to the Output Schedule. This can be incrementally deleted depending on the size of the deployment and Normal Ramp Rate. For non-DSR Generation Resources, SCED will use the QSE-submitted non-DSR Output Schedule once the Non-Spin has been recalled.
- ~~A QSE with a Controllable Load Resource that has provided Non-Spin will ensure that the Load energy and Non-Spin capability is restored within three hours of the recall instruction of the Non-Spin deployment. If the QSE cannot restore within three hours of the recall of Non-Spin deployment by ERCOT, the Non-Spin capability must be replaced by the QSE on other Generation or Controllable Load Resources capable of providing the service.~~
- A QSE with a Load Resource that is not a Controllable Load Resource that has provided Non-Spin will ensure that the Load energy and Non-Spin capability is restored within three hours of the recall instruction of the Non-Spin deployment issued by ERCOT. If the QSE cannot restore within three hours of the ERCOT recall instruction of the Non-Spin deployment, the Non-Spin obligation must be replaced by the QSE from other Non-Spin qualified Resources capable of providing the service.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for a Load Resource that is not a Controllable Load Resource continuously and accurately represents the amount of Load Resource that has been restored following a recall instruction and is available for subsequent deployment.

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

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

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

ERCOT Impact Analysis Report

OBDRR Number	**053**	**OBDRR Title**	**Alignment with NPRR1131, Controllable Load Resource Participation in Non-Spin, and Minor Clean-Ups**
Impact Analysis Date	October 17, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Other Binding Document Revision Request (OBDRR) 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
There are no additional impacts to this OBDRR beyond what was captured in the Impact Analysis for Nodal Protocol Revision Request (NPRR) 1131, Controllable Load Resource Participation in Non-Spin.

Board Report

PGRR Number	107	PGRR Title	Related to NPRR1180, Inclusion of Forecasted Load in Planning Analyses
Date of Decision	December 3, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1180, Inclusion of Forecasted Load in Planning Analyses		
Priority and Rank Assigned	Not applicable		
Planning Guide Sections Requiring Revision	3.1.2.1, All Projects 3.1.3, Project Evaluation 3.1.4.2, Use of Regional Transmission Plan 3.1.7, Steady State Transmission Planning Load Forecast 4.1.1.1, Planning Assumptions		
Related Documents Requiring Revision/Related Revision Requests	NPRR1180		
Revision Description	This Planning Guide Revision Request (PGRR) aligns the Planning Guide with NPRR1180. PGRR107 revises the Planning Guide to address recent amendments to P.U.C. Subst. R. 25.101, Certification Criteria, which became effective on December 20, 2022. Specifically, PGRR107 incorporates the requirement in P.U.C. Subst. R. 25.101(b)(3)(A)(ii)(II) for any review of project need conducted by ERCOT to incorporate the historical load, forecasted load growth, and additional load seeking interconnection, in ERCOT's analysis, while recognizing that ERCOT's Regional Transmission Plan will include only that load that ERCOT has determined to be credibly supported by quantifiable evidence of load growth. PGRR107 also requires a Regional Planning Group (RPG) project submitter to provide such information to ERCOT, when available, for inclusion in ERCOT's planning analyses.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience		

Board Report

	☐ 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	This PGRR aligns the Planning Guide with the Protocols, as revised by NPRR1180.
ROS Decision	On 6/8/23, ROS voted to table PGRR107 and refer the issue to the Planning Working Group (PLWG). There was one abstention from the Independent Generator (Calpine) Market Segment. All Market Segments participated in the vote. On 9/9/24, ROS voted unanimously to recommended approval of PGRR107 as amended by the 8/28/24 ERCOT comments as revised by ROS. All Market Segments participated in the vote. On 10/3/24, ROS voted unanimously to table PGRR107. All Market Segments participated in the vote. On 11/7/24, ROS voted unanimously to endorse and forward to TAC the 10/3/24 ROS Report and 10/16/24 Impact Analysis for PGRR107. All Market Segments participated in the vote.
Summary of ROS Discussion	On 6/8/23, participants reviewed PGRR107. Participants raised questions regarding how the proposed provisions would apply to areas such as interconnection agreements, and requested additional discussion. On 9/9/24, participants reviewed the 8/28/24 ERCOT comments. On 10/3/24, participants reviewed the 9/24/24 ERCOT comments. On 11/7/24, participants reviewed the 10/16/24 Impact Analysis for PGRR107.

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TAC Decision	On 11/20/24, TAC voted to recommend approval of PGRR107 as recommended by ROS in the 11/7/24 ROS Report. There were four abstentions from the Consumer (2) (Residential Consumer, OPUC), Cooperative (GSEC) and Independent Power Marketer (IPM) (SENA) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/20/24, participants expressed concern that estimated load values used in planning studies may not materialize as predicated and stressed the importance of using quality data to calculate load forecasts so that they are as accurate as possible.
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 12/3/24, the ERCOT Board voted unanimously to recommend approval of PGRR107 as recommended by TAC in the 11/20/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	The IMM conditionally supports PGRR107 in concept however the details of the robustness and use of data in developing inputs to the planning analysis are important. IMM support is contingent upon ERCOT's ability to apply reasonable methods to the data they are provided in order to produce the most accurate forecast for use in planning analysis.
ERCOT Opinion	ERCOT supports approval of PGRR107.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR107 and believes it appropriately aligns the Planning Guide with NPRR1180, which incorporates the requirement in P.U.C. Subst. R.25.101(b)(3)(A)(ii)(II) for any reliability-driven transmission project review conduct ed by ERCOT

	to account for historical Load, forecasted Load growth, and additional Load seeking interconnection.

Sponsor	
Name	Martha Henson
E-mail Address	martha.henson@oncor.com
Company	Oncor Electric Delivery Company LLC
Phone Number	214-536-9004
Cell Number	None
Market Segment	Investor Owned Utility

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
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Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
ERCOT 071423	Expressed concern the broad scope could introduce uncertainty and reduce the transparency of the future transmission need and associated projects identified in the ERCOT annual Transmission Planning Assessment and would require ERCOT and Transmission Service Providers (TSPs) to spend significant additional time and resources to meet the obligation under both North American Electric Reliability Corporation (NERC) Reliability Standard and ERCOT planning criteria
Oncor 101323	Incorporated ERCOT independent review of forecasted Load growth, greater detail on the types of information a TSP may provide to ERCOT, and clarified Section 4.1.1.1 and restored language in paragraph 5(a)
ERCOT 121323	Revised language related to Load data provided by TSPs
ERCOT 071524	Aligned terminology with the 7/15/24 ERCOT comments submitted for NPRR1180 that created the term "Substantial Load"
ERCOT 082824	Replaced various instances of the term "Load" with the uncapitalized term "load"
ERCOT 092424	Indicated ERCOT intends to complete the Impact Analysis for PGRR107 prior to the 11/6/24 ROS meeting

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Market Rules Notes

Please note the baseline Planning Guide language in the following section(s) has been updated to reflect the incorporation of the following PGRR into the Planning Guide:

- PGRR098, Consideration of Load Shed in Transmission Planning Criteria (unboxed 8/1/24)
  - Section 4.1.1.1

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

- PGRR115, Related to NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
  - Section 4.1.1.1
- PGRR118, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
  - Section 3.1.2.1
  - Section 3.1.3
  - Section 4.1.1.1

Proposed Guide Language Revision

3.1.2.1 All Projects

Commented [EWG1]: Please note PGRR118 also proposes revisions to this section.

(1) The submittal of each transmission project (60 kV and above) for RPG Project Review should include the following elements:

(a) The proposed project description including expected cost, feasible alternative(s) considered, transmission topology and Transmission Facility modeling parameter data, and all study cases used to generate results supporting the need for the project in electronic format (powerflow data should be in PTI Power System Simulator for Engineering (PSS/E) RAWD format). Also, the submission should include accurate maps and one-line diagrams showing locations of the proposed project and feasible alternatives;

(b) Identification of the SSWG, Dynamics Working Group (DWG), or Regional Transmission Plan powerflow cases used as a basis for the study and any associated changes that describe and allow accurate modeling of the proposed project;

(c) Description and data for all changes made to the SSWG base cases or Regional Transmission Plan cases used to identify the need for the project, such as Generation Resource unavailability and area peak l~~L~~oad forecast;