Variable	Unit	Description
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
HUBDF $_{hb, Houston345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
HBDF $_{b, hb, Houston345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
B $_{hb, Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB $_{Houston345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\,Houston345} = \mathbf{Max\ [-\$251,\ (RTRDP +} \sum_{y} \mathbf{(HUBLMP}_{\,Houston345,\,y} \mathbf{\ *\ RNWF}_{\,y}\mathbf{))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTRDPA}_{\,y})$$

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

The above variables are defined as follows:

Variable	Unit	Description
RTSPP $_{Houston345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA $_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
HUBLMP $_{Houston345, y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.

RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.4 West 345 kV Hub (West 345)

(1) The West 345 kV Hub is composed of the following listed Hub Buses:

No.	ERCOT Operations Hub Bus	kV	Hub
1	MULBERRY	345	WEST
2	BOMSW	345	WEST
3	OECCS	345	WEST
4	BITTCR	345	WEST
5	FSHSW	345	WEST
6	FLCNS	345	WEST
7	GRSES	345	WEST
8	JCKSW	345	WEST
9	MDLNE	345	WEST
10	MOSSW	345	WEST
11	MGSES	345	WEST
12	DCTM	345	WEST
13	ODEHV	345	WEST
14	OKLA	345	WEST
15	REDCREEK	345	WEST
16	SWESW	345	WEST
17	TWINBU	345	WEST

(2) The West 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{\,West345} = \textbf{DASL} - \sum_{c}(\textbf{DAHUBSF}_{\,West345,\,c} * \textbf{DASP}_{\,c}),\ \textbf{if HBBC}_{\,West345} \neq \mathbf{0}$$

$$\textbf{DASPP}_{\,West345} = \textbf{DASPP}_{\,ERCOT345Bus},\ \textbf{if HBBC}_{\,West345} = \mathbf{0}$$

Where:

$$\text{DAHUBSF}_{\,West345,\,c} = \sum_{hb} (\text{HUBDF}_{\,hb,\,West345,\,c} * \text{DAHBSF}_{\,hb,\,West345,\,c})$$

$$\text{DAHBSF}_{\,hb,\,West345,\,c} = \sum_{pb} (\text{HBDF}_{\,pb,\,hb,\,West345,\,c} * \text{DASF}_{\,pb,\,hb,\,West345,\,c})$$

$$\text{HUBDF}_{\,hb,\,West345,\,c} = \text{IF}(\text{HB}_{\,West345,\,c}{=}0,\ 0,\ 1\ /\ \text{HB}_{\,West345,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,West345,\,c} = \text{IF}(\text{PB}_{\,hb,\,West345,\,c}{=}0,\ 0,\ 1\ /\ \text{PB}_{\,hb,\,West345,\,c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DASPP $_{West345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DAHUBSF $_{West345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
DAHBSF $_{hb,West345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
DASF $_{pb,hb,West345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
HUBDF $_{hb,\,West345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
HBDF $_{pb,\,hb,\,West345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
PB $_{hb,\,West345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
HBBC $_{West345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
HB $_{West345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\,West345} = \mathbf{Max\ [-\$251, (RTRSVPOR + RTRDP + \sum_{hb} (HUBDF}_{\,hb,\,West345}\ \mathbf{* (\sum_{y} (RTHBP}_{\,hb,\,West345,\,y}\ \mathbf{* TLMP}_{\,y}\mathbf{) / (\sum_{y} TLMP}_{\,y}\mathbf{))))], if\ HB}_{\,West345}\mathbf{\neq 0}$$

$$\mathbf{RTSPP}_{\,West345} = \mathbf{RTSPP}_{\,ERCOT345Bus}\mathbf{, if\ HB}_{\,West345}\mathbf{=0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTORPA}_{\,y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTORDPA}_{\,y})$$

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

$$\text{RTHBP}_{\,hb,\,West345,\,y} = \sum_{b} (\text{HBDF}_{\,b,\,hb,\,West345} * \text{RTLMP}_{\,b,\,hb,\,West345,\,y})$$

$$\text{HUBDF}_{\,hb,\,West345} = \text{IF}(\text{HB}_{\,West345}=0,\ 0,\ 1 / \text{HB}_{\,West345})$$

$$\text{HBDF}_{\,b,\,hb,\,West345} = \text{IF}(\text{B}_{\,hb,\,West345}=0,\ 0,\ 1 / \text{B}_{\,hb,\,West345})$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{\,West345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
$\text{RTORPA}_{\,y}$	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$\text{RTORDPA}_{\,y}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$\text{RNWF}_{\,y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTHBP}_{\,hb,\,West345,\,y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.

Variable	Unit	Description
$RTLMP_{b, hb, West345, y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$HUBDF_{hb, West345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, West345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, West345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$HB_{West345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation of NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{West345} = \mathbf{Max\ [-\$251,\ (RTRDP + \sum_{y} (HUBLMP}_{West345,\,y}\ \mathbf{*\ RNWF}_{y}\mathbf{))]}$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{West345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.

HUBLMP $_{West345,\ y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.5 Panhandle 345 kV Hub (Pan 345)

(1) The Panhandle 345 kV Hub is composed of the following listed Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	ABERNATH	345	PAN
2	AJ_SWOPE	345	PAN
3	ALIBATES	345	PAN
4	CTT_CROS	345	PAN
5	CTT_GRAY	345	PAN
6	OGALLALA	345	PAN
7	RAILHEAD	345	PAN
8	TESLA	345	PAN
9	TULECNYN	345	PAN
10	W_CW_345	345	PAN
11	WHIT_RVR	345	PAN
12	WINDMILL	345	PAN

(2) The Panhandle 345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\ Pan345} = \mathbf{DASL} - \sum_{c} (\mathbf{DAHUBSF}_{\ Pan345,\ c} * \mathbf{DASP}_{\ c}),\ \textbf{if HBBC}_{\ Pan345} \neq \mathbf{0}$$

$$\mathbf{DASPP}_{\ Pan345} = \mathbf{DASPP}_{\ ERCOT345Bus},\ \textbf{if HBBC}_{\ Pan345} = \mathbf{0}$$

Where:

$$\text{DAHUBSF}_{\ Pan345,\ c} = \sum_{hb} (\text{HUBDF}_{\ hb,\ Pan345,\ c} * \text{DAHBSF}_{\ hb,\ Pan345,\ c})$$

$$\text{DAHBSF}_{\,hb,\,Pan345,\,c} = \sum_{pb}(\text{HBDF}_{\,pb,\,hb,\,Pan345,\,c} * \text{DASF}_{\,pb,\,hb,\,Pan345,\,c})$$

$$\text{HUBDF}_{\,hb,\,Pan345,\,c} = \text{IF}(\text{HB}_{\,Pan345,\,c}{=}0,\ 0,\ 1 / \text{HB}_{\,Pan345,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,Pan345,\,c} = \text{IF}(\text{PB}_{\,hb,\,Pan345,\,c}{=}0,\ 0,\ 1 / \text{PB}_{\,hb,\,Pan345,\,c})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DASPP}_{\,Pan345}$	$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
$\text{DASP}_{\,c}$	$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{\,Pan345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{\,hb,Pan345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{\,pb,hb,Pan345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HUBDF}_{\,hb,\,Pan345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{\,pb,\,hb,\,Pan345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{\,hb,\,Pan345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
$\text{HBBC}_{\,Pan345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
$\text{HB}_{\,Pan345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\,Pan345} = \mathbf{Max\ [-\$251,\ (RTRSVPOR + RTRDP +}$$

$$\sum_{hb} \mathbf{(HUBDF}_{hb,\,Pan345} \mathbf{*} \mathbf{(}\sum_{y} \mathbf{(RTHBP}_{hb,\,Pan345,\,y} \mathbf{*\ TLMP}_{y}\mathbf{)\ /}$$

$$\mathbf{(}\sum_{y} \mathbf{TLMP}_{y}\mathbf{))))],\ if\ HB}_{Pan345}\mathbf{\neq 0}$$

$$\mathbf{RTSPP}_{Pan345} = \mathbf{RTSPP}_{ERCOT345Bus}\mathbf{,\ if\ HB}_{Pan345}\mathbf{=0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

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

$$\text{RTHBP}_{hb,\,Pan345,\,y} = \sum_{b} (\text{HBDF}_{b,\,hb,\,Pan345} * \text{RTLMP}_{b,\,hb,\,Pan345,\,y})$$

$$\text{HUBDF}_{hb,\,Pan345} = \text{IF}(\text{HB}_{Pan345}\text{=0, 0, 1} / \text{HB}_{Pan345})$$

$$\text{HBDF}_{b,\,hb,\,Pan345} = \text{IF}(\text{B}_{hb,\,Pan345}\text{=0, 0, 1} / \text{B}_{hb,\,Pan345})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RTSPP_{Pan345}	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{RTHBP}_{hb,\,Pan345,\,y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$\text{RTLMP}_{b,\,hb,\,Pan345,\,y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb* for the SCED interval *y*.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.

Variable	Unit	Description
HUBDF $_{hb, Pan345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
HBDF $_{b, hb, Pan345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
B $_{hb, Pan345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB $_{Pan345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP}_{\,Pan345} = \textbf{Max [-\$251, (RTRDP} + \sum_{y} \textbf{(HUBLMP}_{\,Pan345,\,y} * \textbf{RNWF}_{\,y}\textbf{))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTRDPA}_{\,y})$$

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

The above variables are defined as follows:

Variable	Unit	Description
RTSPP $_{Pan345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA $_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
HUBLMP $_{Pan345, y}$	\$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.

TLMP $_y$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

[NPRR941, NPRR1007, and NPRR1057: Insert applicable portions of Section 3.5.2.6 below upon system implementation for NPRR941 or NPRR1057; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; and renumber accordingly:]

3.5.2.6 Lower Rio Grande Valley Hub (LRGV 138/345)

(1) The Lower Rio Grande Valley Hub 138/345 kV Hub is composed of the following listed Hub Buses:

No.	ERCOT Operations Hub Bus	kV	Hub
1	AIRPORT	138	LRGV
2	ALBERTA	138	LRGV
3	BATES	138	LRGV
4	FRONTERA	138	LRGV
5	GARZA	138	LRGV
6	HARLNSW	138	LRGV
7	HEC	138	LRGV
8	KEY_SW	138	LRGV
9	LA_PALMA_345	345	LRGV
10	LA_PALMA_138	138	LRGV
11	LASPULGA	138	LRGV
12	LISTON	138	LRGV
13	LOMA_ALT	138	LRGV
14	MARCONI	138	LRGV
15	MILHWY	138	LRGV
16	MILITARY	138	LRGV
17	MV_WEDN4	138	LRGV
18	N_MCALLN	138	LRGV
19	NEDIN_345	345	LRGV
20	NEDIN_138	138	LRGV
21	OLEANDER	138	LRGV
22	P_ISABEL	138	LRGV
23	PALMHRTP	138	LRGV
24	PALMITO_345	345	LRGV

25	PALMITO_138	138	LRGV
26	PAREDES	138	LRGV
27	PHARMVEC	138	LRGV
28	PHARR	138	LRGV
29	PRICE_RD	138	LRGV
30	RAILROAD	138	LRGV
31	RAYMND2	138	LRGV
32	REDTAP	138	LRGV
33	RIO_GRAN	138	LRGV
34	RIOHONDO_345	345	LRGV
35	RIOHONDO_138	138	LRGV
36	ROMA_SW	138	LRGV
37	S_MCALLN	138	LRGV
38	SCARBIDE	138	LRGV
39	SILASRAY	138	LRGV
40	STEWART	138	LRGV
41	WESLACO	138	LRGV

(2) The Lower Rio Grande Valley 138/345 kV Hub Price uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\,LRGV\,138/345} = \mathbf{DASL} - \sum_{c} (\mathbf{DAHUBSF}_{\,LRGV\,138/345,\,c} * \mathbf{DASP}_{\,c}), \text{ if } \mathbf{HBBC}_{\,LRGV138/345} \neq 0$$

$$\mathbf{DASPP}_{\,LRGV138/345} = \mathbf{DASPP}_{\,ERCOT345Bus}, \text{ if } \mathbf{HBBC}_{\,LRGV138/345} = 0$$

Where:

$$\text{DAHUBSF}_{\,LRGV138/345,\,c} = \sum_{hb} (\text{HUBDF}_{\,hb,\,LRGV138/345,\,c} * \text{DAHBSF}_{\,hb,\,LRGV138/345,\,c})$$

$$\text{DAHBSF}_{\,hb,\,LRGV138/345,\,c} = \sum_{pb} (\text{HBDF}_{\,pb,\,hb,\,LRGV138/345,\,c} * \text{DASF}_{\,pb,\,hb,\,LRGV138/345,\,c})$$

$$\text{HUBDF}_{\,hb,\,LRGV138/345,\,c} = \text{IF}(\text{HB}_{\,LRGV138/345,\,c} = 0,\ 0,\ 1 / \text{HB}_{\,LRGV138/345,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,LRGV138/345,\,c} = \text{IF}(\text{PB}_{\,hb,\,LRGV138/345,\,c}=0,\ 0,\ 1 / \text{PB}_{\,hb,\,LRGV138/345,\,c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DASPP $_{LRGV138/345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP $_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
DAHUBSF $_{LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
DAHBSF $_{hb, LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
DASF $_{pb,hb, LRGV138/345,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
HUBDF $_{hb, LRGV138/345,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
HBDF $_{pb, hb, LRGV138/345,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
PB $_{hb, LRGV138/345,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the Hub with at least one energized power flow bus for the constraint *c*.
HBBC $_{LRGV138/345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus in base case.
HB $_{LRGV138/345,c}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus for the constraint *c*.
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP}_{\,LRGV138/345} = \textbf{Max [-\$251, (RTRDP + } \sum_{y} \textbf{(HUBLMP}_{\,LRGV138/345,\,y} \textbf{ * RNWF}_{\,y}\textbf{))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTRDPA}_{\,y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{LRGV138/345kV}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$HUBLMP_{LRGV138/345,\ y}$	$/MWh	*Hub Locational Marginal Price*—The Hub LMP for the Hub for the SCED Interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.2.6 ERCOT Hub Average 345 kV Hub (ERCOT 345)

(1) The ERCOT Hub Average 345 kV Hub price for Day-Ahead is calculated for each hour using the aggregated Shift Factors of four Hubs: the North 345 kV Hub, the South 345 kV Hub, the Houston 345 kV Hub, and the West 345 kV Hub. The ERCOT Hub Average 345 kV Hub price for Real-Time is the simple average of four prices from the applicable time period: the North 345 kV Hub price, the South 345 kV Hub price, the Houston 345 kV Hub price, and the West 345 kV Hub price. The Panhandle 345 kV Hub is not included in either the Day-Ahead or Real-Time ERCOT Hub Average 345 kV Hub price.

[NPRR941: Replace paragraph (1) above upon system implementation:]

(1) The ERCOT Hub Average 345 kV Hub price for Day-Ahead is calculated for each hour using the aggregated Shift Factors of four Hubs: the North 345 kV Hub, the South 345 kV Hub, the Houston 345 kV Hub, and the West 345 kV Hub. The ERCOT Hub Average 345 kV Hub price for Real-Time is the simple average of four prices from the applicable time period: the North 345 kV Hub price, the South 345 kV Hub price, the Houston 345 kV Hub price, and the West 345 kV Hub price. The Panhandle 345 kV

Hub and the Lower Rio Grande Valley 138/345 kV Hub are not included in either the Day-Ahead or Real-Time ERCOT Hub Average 345 kV Hub price.

(2) The Day-Ahead Settlement Point Price for the Hub "ERCOT 345" for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{\mathit{ERCOT345}} = \textbf{DASL} - \sum_{c}(\textbf{DAHUBSF}_{\mathit{ERCOT345,\,c}} * \textbf{DASP}_{c}),\ \textbf{if HBBC}_{\mathit{ERCOT345Bus}} \neq 0$$

$$\textbf{DASPP}_{\mathit{ERCOT345}} = \textbf{DASPP}_{\mathit{ERCOT345Bus}},\ \textbf{if HBBC}_{\mathit{ERCOT345Bus}} = 0$$

Where:

$$\text{DAHUBSF}_{\mathit{ERCOT345,\,c}} = (\text{DAHUBSF}_{\mathit{North345,\,c}} + \text{DAHUBSF}_{\mathit{South345,\,c}} + \text{DAHUBSF}_{\mathit{Houston345,\,c}} + \text{DAHUBSF}_{\mathit{West345,\,c}}) / 4$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DASPP}_{\mathit{ERCOT345}}$	\$/MWh	*Day-Ahead Settlement Point Price at ERCOT 345*—The DAM Settlement Point Price at ERCOT 345 Hub for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
DASP_{c}	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{ERCOT345,c}}$	none	*Day-Ahead Shift Factor of ERCOT 345* —The DAM aggregated Shift Factor of ERCOT 345 Hub for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{North345,c}}$	none	*Day-Ahead Shift Factor of North 345*—The DAM aggregated Shift Factor of the North 345 Hub for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{South345,c}}$	none	*Day-Ahead Shift Factor of South 345*—The DAM aggregated Shift Factor of the South 345 Hub for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{Houston345,c}}$	none	*Day-Ahead Shift Factor of Houston 345*—The DAM aggregated Shift Factor of the Houston 345 Hub for the constraint *c* for the hour.
$\text{DAHUBSF}_{\mathit{West345,c}}$	none	*Day-Ahead Shift Factor of West 345*—The DAM aggregated Shift Factor of the West 345 Hub for the constraint *c* for the hour.
$\text{HBBC}_{\mathit{ERCOT345Bus}}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus in base case. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(3) The Real-Time Settlement Point Price for the Hub "ERCOT 345" for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\,ERCOT345} = (\mathbf{RTSPP}_{\,North345} + \mathbf{RTSPP}_{\,South345} + \mathbf{RTSPP}_{\,Houston345} + \mathbf{RTSPP}_{\,West345}) / 4$$

The above variables are defined as follows:

Variable	Unit	Definition
$RTSPP_{\,ERCOT345}$	$/MWh	*Real-Time Settlement Point Price at ERCOT 345*—The Real-Time Settlement Point Price at ERCOT 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{\,North345}$	$/MWh	*Real-Time Settlement Point Price at North 345*—The Real-Time Settlement Point Price at the North 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{\,South345}$	$/MWh	*Real-Time Settlement Point Price at South 345*—The Real-Time Settlement Point Price at the South 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{\,Houston345}$	$/MWh	*Real-Time Settlement Point Price at Houston 345*—The Real-Time Settlement Point Price at the Houston 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{\,West345}$	$/MWh	*Real-Time Settlement Point Price at West 345*—The Real-Time Settlement Point Price at the West 345 Hub for the 15-minute Settlement Interval.

3.5.2.7 ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus)

(1) The ERCOT Bus Average 345 kV Hub is composed of the Hub Buses listed in Section 3.5.2.1, North 345 kV Hub (North 345); Section 3.5.2.2, South 345 kV Hub (South 345); Section 3.5.2.3, Houston 345 kV Hub (Houston 345); and Section 3.5.2.4, West 345 kV Hub (West 345). The Panhandle 345 kV Hub is not included in the ERCOT Bus Average 345 kV Hub price.

[NPRR941: Replace paragraph (1) above upon system implementation:]

(1) The ERCOT Bus Average 345 kV Hub is composed of the Hub Buses listed in Section 3.5.2.1, North 345 kV Hub (North 345); Section 3.5.2.2, South 345 kV Hub (South 345); Section 3.5.2.3, Houston 345 kV Hub (Houston 345); and Section 3.5.2.4, West 345 kV Hub (West 345). The Panhandle 345 kV Hub and the Lower Rio Grande Valley 138/345 kV Hub are not included in the ERCOT Bus Average 345 kV Hub price.

(2) The ERCOT Bus Average 345 kV Hub uses the aggregated Shift Factors of the Hub Buses for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\,ERCOT345Bus} = \mathbf{DASL} - \sum_{c} (\mathbf{DAHUBSF}_{\,ERCOT345Bus,\,c} * \mathbf{DASP}_{\,c}), \text{ if } \mathbf{HBBC}_{\,ERCOT345Bus} \neq 0$$

$$\mathbf{DASPP}_{\,ERCOT345Bus} = 0, \text{ if } \mathbf{HBBC}_{\,ERCOT345Bus} = 0$$

Where:

$$\text{DAHUBSF}_{\,ERCOT345Bus,\,c} = \sum_{hb} (\text{HUBDF}_{\,hb,\,ERCOT345Bus,\,c} * \text{DAHBSF}_{\,hb,\,ERCOT345Bus,\,c})$$

$$\text{DAHBSF}_{\,hb,\,ERCOT345Bus,\,c} = \sum_{pb} (\text{HBDF}_{\,pb,\,hb,\,ERCOT345Bus,\,c} * \text{DASF}_{\,pb,\,hb,\,ERCOT345Bus,\,c})$$

$$\text{HUBDF}_{\,hb,\,ERCOT345Bus,\,c} = \text{IF}(\text{HB}_{\,ERCOT345Bus,\,c}{=}0,\ 0,\ 1\ /\ \text{HB}_{\,ERCOT345Bus,\,c})$$

$$\text{HBDF}_{\,pb,\,hb,\,ERCOT345Bus,\,c} = \text{IF}(\text{PB}_{\,hb,\,ERCOT345Bus,\,c}{=}0,\ 0,\ 1\ /\ \text{PB}_{\,hb,\,ERCOT345Bus,\,c})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{DASPP}_{\,ERCOT345Bus}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
$\text{DASP}_{\,c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$\text{DAHUBSF}_{\,ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the Hub* —The DAM aggregated Shift Factor of a Hub for the constraint *c* for the hour.
$\text{DAHBSF}_{\,hb,ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the Hub Bus*—The DAM aggregated Shift Factor of a Hub Bus *hb* for the constraint *c* for the hour.
$\text{DASF}_{\,pb,hb,ERCOT345Bus,c}$	none	*Day-Ahead Shift Factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HUBDF}_{\,hb,ERCOT345Bus,c}$	none	*Hub Distribution Factor per Hub Bus in a constraint*—The distribution factor of Hub Bus *hb* for the constraint *c* for the hour.
$\text{HBDF}_{\,pb,\,hb,\,ERCOT345Bus,c}$	none	*Hub Bus Distribution Factor per power flow bus of Hub Bus in a constraint*—The distribution factor of power flow bus *pb* that is a component of Hub Bus *hb* for the constraint *c* for the hour.
pb	none	An energized power flow bus that is a component of a Hub Bus for the constraint *c*.
$\text{PB}_{\,hb,\,ERCOT345Bus,c}$	none	The total number of energized power flow buses in Hub Bus *hb* for the constraint *c*.
hb	none	A Hub Bus that is a component of the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized power flow bus for the constraint *c*. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
$\text{HBBC}_{\,ERCOT345Bus}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus in base case. The Hub "ERCOT 345 Bus" includes any Hub Bus defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
$\text{HB}_{\,ERCOT345Bus,c}$	none	The total number of Hub Buses in the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus) with at least one energized component in each Hub Bus for the constraint *c*. The Hub "ERCOT 345 Bus" includes any Hub Bus

Variable	Unit	Definition
		defined in the Hub "North 345", "South 345", "Houston 345" and "West 345".
c	none	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\,ERCOT345Bus} = \mathbf{Max\ [-\$251, (RTRSVPOR + RTRDP +} \sum_{hb} \mathbf{(HUBDF}_{\,hb,\,ERCOT345Bus} \mathbf{*\ (} \sum_{y} \mathbf{(RTHBP}_{\,hb,\,ERCOT345Bus,\,y} \mathbf{*\ TLMP}_{\,y}\mathbf{)\ /\ (} \sum_{y} \mathbf{TLMP}_{\,y}\mathbf{))))],\ if\ HB}_{\,ERCOT345Bus} \mathbf{\neq 0}$$

$$\mathbf{RTSPP}_{\,\mathbf{ERCOT345Bus}} = \mathbf{0,\ if\ HB}_{\,\mathbf{ERCOT345Bus}} \mathbf{=0}$$

Where:

$$\text{RTRSVPOR} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTORPA}_{\,y})$$

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{\,y} * \text{RTORDPA}_{\,y})$$

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

$$\text{RTHBP}_{\,hb,\,ERCOT345Bus,\,y} = \sum_{b} (\text{HBDF}_{\,b,\,hb,\,ERCOT345Bus} * \text{RTLMP}_{\,b,\,hb,\,ERCOT345Bus,\,y})$$

$$\text{HUBDF}_{\,hb,\,ERCOT345Bus} = 1 / (\text{HB}_{\,North345} + \text{HB}_{\,South345} + \text{HB}_{\,Houston345} + \text{HB}_{\,West345})$$

If Electrical Bus *b* is a component of "North 345"

$$\text{HBDF}_{\,b,\,hb,\,ERCOT345Bus} = \text{IF}(\text{B}_{\,hb,\,North345}{=}0,\ 0,\ 1 / \text{B}_{\,hb,\,North345})$$

Otherwise

If Electrical Bus *b* is a component of "South 345"

$$\text{HBDF}_{\,b,\,hb,\,ERCOT345Bus} = \text{IF}(\text{B}_{\,hb,\,South345}{=}0,\ 0,\ 1 / \text{B}_{\,hb,\,South345})$$

Otherwise

If Electrical Bus *b* is a component of "Houston 345"

$$\text{HBDF}_{\,b,\,hb,\,ERCOT345Bus} = \text{IF}(\text{B}_{\,hb,\,Houston345}{=}0,\ 0,\ 1 / \text{B}_{\,hb,\,Houston345})$$

Otherwise

$$\text{HBDF}_{\,b,\,hb,\,ERCOT345Bus} = \text{IF}(\text{B}_{\,hb,\,West345}{=}0,\ 0,\ 1 / \text{B}_{\,hb,\,West345})$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{ERCOT345Bus}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
$RTORPA_{y}$	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$RTORDPA_{y}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$RTHBP_{hb, ERCOT345Bus, y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$RTLMP_{b, hb, ERCOT345Bus, y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$HUBDF_{hb, ERCOT345Bus}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, ERCOT345Bus}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, North345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "North 345."
$B_{hb, South345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "South 345."
$B_{hb, Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "Houston 345."
$B_{hb, West345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "West 345."
hb	none	A Hub Bus that is a component of the Hub.
$HB_{North345}$	none	The total number of Hub Buses in "North 345."
$HB_{South345}$	none	The total number of Hub Buses in "South 345."
$HB_{Houston345}$	none	The total number of Hub Buses in "Houston 345."
$HB_{West345}$	none	The total number of Hub Buses in "West 345."

[NPRR1007 and NPRR1057: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1057:]

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\mathit{ERCOT345Bus}} = \mathbf{Max\ [-\$251, (RTRDP + \sum_{y} (HUBLMP_{\mathit{ERCOT345Bus,y}} * RNWF_{\mathit{y}}))]}$$

Where:

$$\text{RTRDP} = \sum_{y} (\text{RNWF}_{y} * \text{RTRDPA}_{y})$$

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

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{\mathit{ERCOT345Bus}}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that are calculated from the Real-Time Reliability Deployment Price Adder for Energy.
RTRDPA_{y}	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$\text{HUBLMP}_{\mathit{ERCOT345Bus,y}}$	\$/MWh	*Hub Locational Marginal Price for the ERCOT345Bus*—The Hub LMP for the ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus), for the SCED Interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
TLMP_{y}	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

3.5.3 ERCOT Responsibilities for Managing Hubs

3.5.3.1 Posting of Hub Buses and Electrical Buses included in Hubs

(1) ERCOT shall post a list of all the Hub Buses included in each Hub on the ERCOT website. The list must include the name and kV rating for each Electrical Bus included in each Hub Bus.

3.5.3.2 Calculation of Hub Prices

(1) ERCOT shall calculate Hub prices for each Settlement Interval as identified in the description of each Hub.

3.6 Load Participation

3.6.1 Load Resource Participation

(1) A Load Resource may participate by providing:

(a) Ancillary Service:

(i) Regulation Up (Reg-Up) Service as a Controllable Load Resource capable of providing Primary Frequency Response;

(ii) Regulation Down (Reg-Down) Service as a Controllable Load Resource capable of providing Primary Frequency Response;

(iii) Responsive Reserve (RRS) as a Controllable Load Resource qualified for Security-Constrained Economic Dispatch (SCED) Dispatch and capable of providing Primary Frequency Response, or as a Load Resource controlled by high-set under-frequency relay;

(iv) ERCOT Contingency Reserve Service (ECRS) as a Controllable Load Resource qualified for SCED Dispatch and capable of providing Primary Frequency Response, or as a Load Resource that may or may not be controlled by high-set under-frequency relay;

(v) Non-Spinning Reserve (Non-Spin) as a Controllable Load Resource qualified for SCED Dispatch or as a Load Resource that is not a Controllable Load Resource and that is not controlled by under-frequency relay; and

(vi) A Load Resource that is not a Controllable Load Resource cannot simultaneously provide Non-Spin and RRS in Real-Time;

(b) Energy in the form of Demand response from a Controllable Load Resource in Real-Time via SCED;

(c) Emergency Response Service (ERS) for hours in which the Load Resource does not have an Ancillary Service Resource Responsibility; and

[NPRR1007: Replace paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(c) Emergency Response Service (ERS) for hours in which the Load Resource has a Resource Status of OUTL; and

(d) Voluntary Load response in Real-Time.

(2) Except for voluntary Load response and ERS, loads participating in any ERCOT market must be registered as a Load Resource and are subject to qualification testing administered by ERCOT.

(3) All ERCOT Settlements resulting from Load Resource participation are made only with the Qualified Scheduling Entity (QSE) representing the Load Resource.

(4) A QSE representing a Load Resource and submitting a bid to buy for participation in SCED, as described in Section 6.4.3.1, RTM Energy Bids, must represent the Load Serving Entity (LSE) serving the Load of the Load Resource. If the Load Resource is an Aggregate Load Resource (ALR), the QSE must represent the LSE serving the Load of all sites within the ALR.

(5) The Settlement Point for a Controllable Load Resource is its Load Zone Settlement Point. For an Energy Storage Resource (ESR), the Settlement Point for the charging Load withdrawn by the modeled Controllable Load Resource associated with the ESR is the Resource Node of the modeled Generation Resource associated with the ESR.

(6) QSEs shall not submit offers for Load Resources containing sites associated with a Dynamically Scheduled Resource (DSR).

[NPRR1000: Delete paragraph (6) above upon system implementation and renumber accordingly.]

(7) Each Resource Entity that represents one or more Load Resources shall ensure that each Load Resource it represents meets at least one of the following conditions:

(a) The Load Resource is not located behind an Electric Service Identifier (ESI ID) that corresponds to a Critical Load;

(b) The Load Resource is located behind an ESI ID that corresponds to a Critical Load, but the Load Resource is not a Critical Load and does not include a Critical Load; or

(c) The Load Resource is located behind an ESI ID that corresponds to a Critical Load, but electric service from the ERCOT System is not required for the provision of the critical service due to the availability of back-up generation or other technologies at the site.

(8) As a condition of obtaining and maintaining registration as a Load Resource, the Resource Entity for the Load Resource must have submitted an attestation, in a form deemed acceptable by ERCOT, stating that one of the conditions set forth in paragraph (7) above is true, and that if either of the conditions in paragraph (7)(b) or (7)(c) is true, then all of the Load Resource's offered Demand response capacity will be available if deployed by ERCOT during an emergency.

(9) Each QSE that represents one or more ERS Resources shall ensure that each ERS Resource identified in any ERS Submission Form submitted by the QSE meets at least one of the following conditions:

(a) The ERS Resource and each site within the ERS Resource are not located behind an ESI ID or unique meter identifier that corresponds to a Critical Load and are not used to support a Critical Load; or

(b) The ERS Resource or one or more sites within the ERS Resource are behind an ESI ID or unique meter identifier that corresponds to a Critical Load, but the ERS Resource and each site within the ERS Resource are not a Critical Load, do not include a Critical Load, and are not used to support a Critical Load; or

(c) The ERS Resource or one or more sites within the ERS Resource are behind an ESI ID or unique meter identifier that corresponds to a Critical Load, but electric service from the ERCOT System is not required for the provision of the critical service due to the availability of back-up generation or other technologies at the site, and neither the ERS Resource nor any site within the ERS Resource is used to support a Critical Load.

3.6.2 Decision Making Entity for a Resource

(1) Each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall submit a declaration to ERCOT, using Section 23, Form C, Managed Capacity Declaration, as to which Decision Making Entity (DME) has control of each of its Resources. The declaration shall be signed by the Authorized Representative of the Resource Entity. In addition, each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall notify ERCOT of any known changes in that declaration no later than 14 days prior to the date that the change takes effect, or as soon as possible in a situation where the Resource Entity is unable to meet the 14-day Notice requirement. However, in no event may the Resource Entity inform ERCOT later

than 72 hours before the date on which the change in DME takes effect. Upon ERCOT's request, each Resource Entity that owns a Resource, except for a Load Resource that is not SCED qualified, shall provide ERCOT with sufficient information or documentation to verify the DME's control of the Resource. ERCOT shall update the DME for a Resource effective the first Operating Hour of the Operating Day after ERCOT satisfactorily confirms the Resource Entity's most recent declaration, but not sooner than the effective date specified on the Resource Entity's most recent declaration.

3.7 Resource Parameters

(1) A Resource Entity shall register Generation Resources, Settlement Only Generators (SOGs), and Load Resources pursuant to Planning Guide Section 6.8, Resource Registration Procedures. The Resource Parameters, listed in Section 3.7.1, Resource Parameter Criteria, are a subset of Resource Registration data defined in the Resource Registration Glossary.

[NPRR995 and NPRR1002: Replace applicable portions of paragraph (1) above with the following upon system implementation:]

(1) A Resource Entity shall register its Generation Resources, Energy Storage Resources (ESRs), Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs), and Load Resources pursuant to Planning Guide Section 6.8, Resource Registration Procedures. The Resource Parameters, listed in Section 3.7.1, Resource Parameter Criteria, are a subset of Resource Registration data defined in the Resource Registration Glossary.

(2) ERCOT shall provide each Qualified Scheduling Entity (QSE) that represents a Resource the ability to submit changes to Resource Parameters for that Resource as described in Section 3.7.1.

(3) The QSE may revise Resource Parameters only with sufficient documentation to justify a change in Resource Parameters.

(4) ERCOT shall use the Resource Parameters as inputs into the Day-Ahead Market (DAM), Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), Resource Limit Calculator, Load Frequency Control (LFC), and other ERCOT business processes.

(5) The Independent Market Monitor (IMM) may require the QSE to provide justification for the Resource Parameters submitted.

3.7.1 Resource Parameter Criteria

3.7.1.1 Generation Resource Parameters

(1) Generation Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation include:

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Minimum On-Line time;

(d) Minimum Off-Line time;

(e) Maximum On-Line time;

(f) Maximum daily starts;

(g) Maximum weekly starts;

(h) Maximum weekly energy;

(i) Hot start time;

(j) Intermediate start time;

(k) Cold start time;

(l) Hot to intermediate time; and

(m) Intermediate to cold time.

3.7.1.2 Load Resource Parameters

(1) Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation, which may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, General Capacity Testing Requirements, include the following for each of its Load Resources that is a non-Controllable Load Resource:

(a) Maximum interruption time;

(b) Maximum daily deployments;

(c) Maximum weekly deployments;

(d) Maximum weekly energy;

(e) Minimum notice time;

(f) Minimum interruption time; and

(g) Minimum restoration time.

(2) Resource Parameters that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation, which may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, include the following for each of its Controllable Load Resources, including Aggregate Load Resources (ALRs):

(a) Normal Ramp Rate curve;

(b) Emergency Ramp Rate curve;

(c) Maximum deployment time; and

(d) Maximum weekly energy.

(3) Resource Parameters submitted by a Resource Entity must also include, for each of its ALRs, mapping between the ALR and the individually metered Loads, by Electric Service Identifier (ESI ID) or, in the case of a Non-Opt-In Entity (NOIE), equivalent unique meter identifier, comprising the ALR.

[NPRR1002: Insert Section 3.7.1.3 below upon system implementation:]

3.7.1.3 Energy Storage Resource Parameters

(1) Resource Parameters for an ESR that may be modified, with documented reason for change, by the QSE for immediate use upon ERCOT validation include:

(a) Normal Ramp Rate curve; and

(b) Emergency Ramp Rate curve.

3.7.2 Changes in Resource Parameters with Operational Impacts

(1) The QSE representing each Resource shall have the responsibility to submit changes to Resource Parameters for those Resource Parameters related to the Current Operating Plan (COP), as described in Section 3.9, Current Operating Plan (COP), and to Real-Time operations as described in Section 6, Adjustment Period and Real-Time Operations. If the QSE cancels a Resource Parameter submission, ERCOT will use as a default the Resource Parameter that is registered in the Network Operations Model.

3.7.3 Resource Parameter Validation

(1) ERCOT shall verify that changes to Resource Parameters submitted by the QSE representing the Resource comply with the Resource Registration Glossary. If a Resource Parameter is determined to be invalid, then ERCOT shall reject it and provide written notice to the QSE representing the Resource of the reason for the rejection.

3.8 Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources

[NPRR1026: Replace Section 3.8 above with the following upon system implementation:]

3.8 Special Considerations

3.8.1 Split Generation Resources

(1) When a generation meter is split, as provided for in Section 10.3.2.1, Generation Resource Meter Splitting, two or more independent Generation Resources must be created in the ERCOT Network Operations Model according to Section 3.10.7.2, Modeling of Resources and Transmission Loads, to function in all respects as Split Generation Resources in ERCOT System operation. A Combined Cycle Train may not be registered in ERCOT as a Split Generation Resource. A Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) may not be registered in ERCOT as a Split Generation Resource.

(2) Each Qualified Scheduling Entity (QSE) representing a Split Generation Resource shall collect and shall submit to ERCOT the Resource Parameters defined under Section 3.7, Resource Parameters, for the Split Generation Resource it represents. The parameters provided must be consistent with the parameters submitted by each other QSE that represents a Split Generation Resource from the same Generation Resource. The parameters submitted for each Split Generation Resource for limits and ramp rates must be according to the capability of the Split Generation Resource represented by the QSE. Startup and shutdown times, time to change status and number of starts must be identical for all the Split Generation Resources from the same Generation Resource submitted by each QSE. ERCOT shall review data submitted by each QSE representing Split Generation Resources for consistency and notify each QSE of any errors.

(3) Each Split Generation Resource may be represented by a different QSE. The Resource Entities that own or control the Split Generation Resources from a single Generation Resource must designate a Master QSE. Each QSE representing a Split Generation Resource must comply in all respects to the requirements of a Generation Resource specified under these Protocols.

(4) The Master QSE shall:

(a) Serve as the Single Point of Contact for the Generation Resource, as required by Section 3.1.4.1, Single Point of Contact;

(b) Provide real-time telemetry for the total Generation Resource, as specified in Section 6.5.5.2, Operational Data Requirements; and

(c) Receive Verbal Dispatch Instructions (VDIs) from ERCOT, as specified in Section 6.5.7.8, Dispatch Procedures.

(5) Each QSE is responsible for representing its Split Generation Resource in its Current Operating Plan (COP). During the Reliability Unit Commitment (RUC) Study Periods, any conflict in the Resource Status of a Split Generation Resource in the COP is resolved according to the following:

(a) If a Split Generation Resource has a Resource Status of OUT for any hour in the COP, then any other QSEs' COP entries for their Split Generation Resources from the same Generation Resource are also considered unavailable for the hour;

(b) If the QSEs for all Split Generation Resources from the same Generation Resource have submitted a COP and at least one of the QSEs has an On-Line Resource Status in a given hour, then the status for all Split Generation Resources for the Generation Resource is considered to be On-Line for that hour, except if any of the QSEs has indicated in the COP a Resource Status of OUT.

(6) Each QSE representing a Split Generation Resource shall update its individual Resource Status appropriately.

(7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split Generation Resources in a single Generation Resource must be committed or decommitted together.

[NPRR1007: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves, Ancillary Service Offers, and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split Generation Resources in a single Generation Resource must be committed or decommitted together.

(8) Each QSE submitting verifiable cost data to ERCOT shall coordinate among all owners of a single Generation Resource to provide individual Split Generation Resource data consistent with the total verifiable cost of the entire Generation Resource. ERCOT may

compare the total verifiable costs with other similarly situated Generation Resources to determine the reasonability of the cost.

3.8.2 Combined Cycle Generation Resources

(1) ERCOT shall assign a logical Resource Node for use in the Day-Ahead Market (DAM), RUC, Supplemental Ancillary Services Market (SASM), Security-Constrained Economic Dispatch (SCED) and Load Frequency Control (LFC) to each registered Combined Cycle Train. Each Combined Cycle Generation Resource registered in the Combined Cycle Train will be mapped to the Combined Cycle Train logical Resource Node for the purposes of evaluating and settling each Combined Cycle Generation Resource's Three-Part Supply Offer and Ancillary Service Offer in the DAM, RUC and SCED. Each generation unit identified in the Combined Cycle Train registration for a Combined Cycle Generation Resource configuration will be mapped to its designated Resource Node as determined in accordance with these Protocols and the Other Binding Document titled "Procedure for Identifying Resource Nodes."

[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall assign a logical Resource Node for use in the Day-Ahead Market (DAM), RUC, Security-Constrained Economic Dispatch (SCED) and Load Frequency Control (LFC) to each registered Combined Cycle Train. Each Combined Cycle Generation Resource registered in the Combined Cycle Train will be mapped to the Combined Cycle Train logical Resource Node for the purposes of evaluating and settling each Combined Cycle Generation Resource's Three-Part Supply Offer and Ancillary Service Offer in the DAM, RUC and SCED. Each generation unit identified in the Combined Cycle Train registration for a Combined Cycle Generation Resource configuration will be mapped to its designated Resource Node as determined in accordance with these Protocols and the Other Binding Document titled "Procedure for Identifying Resource Nodes."

(2) If any of the generation units, designated in the Combined Cycle Train registration as a primary generation unit in a Combined Cycle Generation Resource, is isolated from the ERCOT Transmission Grid because of a transmission Outage reported in the Outage Scheduler, the DAM and RUC applications shall select an alternate generation unit for use in the application.

(3) Three-Part Supply Offers submitted for a Combined Cycle Generation Resource will be modeled as High Reasonability Limit (HRL)-weighted injections at the Resource Connectivity Nodes of the associated Generation Resources. ERCOT shall use the logical Resource Node to settle these offers.

(4) In the DAM and RUC, ERCOT shall model the energy injection from each generation unit registered to the Combine Cycle Generation Resource designated in a Three-Part Supply Offer as follows:

(a) The energy injection for each generation unit registered in the Combined Cycle Generation Resource designated in a Three-Part Supply Offer shall be the offered energy injection for the selected price point on the Three-Part Supply Offer's Energy Offer Curve times a weight factor as determined in paragraph (4)(b) below.

(b) The weight factor for each generation unit registered in a Combined Cycle Generation Resource shall be the generation unit's HRL, as specified in the Resource Registration data provided to ERCOT pursuant to Planning Guide Section 6.8.2, Resource Registration Process, divided by the total of all HRL values for the generation units registered in the designated Combined Cycle Generation Resource.

(5) In the Network Operations Network Models used in the DAM, RUC and SCED applications, each generation unit identified in the Combined Cycle Train registration must be modeled at its Resource Connectivity Node.

(6) For Ancillary Services offered and provided from Combined Cycle Generation Resources, ERCOT shall apply, without exception, the same rules and requirements specified in these Protocols for the DAM, RUC and Adjustment Period and Real-Time markets that apply to Ancillary Services provided from any other Generation Resources.

(a) ERCOT systems shall determine the High and Low Ancillary Service Limits (HASL and LASL) for a Combined Cycle Generation Resource as follows:

(i) In Real Time, relative to the telemetered High Sustained Limit (HSL) for the Combined Cycle Generation Resource, or

(ii) During the DAM and RUC study periods, relative to the HSL in the COP.

(b) The QSE shall assure that the Combined Cycle Generation Resource designated as On-Line through telemetry or in the COP can meet its Ancillary Service Resource Responsibility.

[NPRR1007: Replace paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) For Ancillary Services offered and provided from Combined Cycle Generation Resources, ERCOT shall apply, without exception, the same rules and requirements specified in these Protocols for the DAM, RUC and Adjustment Period and Real-Time markets that apply to Ancillary Services provided from any other Generation Resources.

(a) ERCOT systems shall determine the operating limits for a Combined Cycle Generation Resource as follows:

(i) In Real-Time, relative to the telemetered capacity limits, ramp rates, and Ancillary Service capabilities for the Combined Cycle Generation Resource;

(ii) During the DAM study period, relative to the HSL in the COP; or

(iii) During the RUC Study Period, relative to the capacity limits and Ancillary Service capabilities in the COP.

3.8.3 Quick Start Generation Resources

(1) The QSE for a Quick Start Generation Resource (QSGR) that is available for deployment by SCED shall set the COP Resource Status to OFFQS, and the COP Low Sustained Limit (LSL) and COP HSL values to the expected sustainable LSL and HSL for the QSGR for the hour. If the QSGR is providing Non-Spinning Reserve (Non-Spin) service, then the Ancillary Service Resource Responsibility for Non-Spin shall be set to the Resource's QSE-assigned Non-Spin responsibility in the COP. If the QSGR is providing ERCOT Contingency Reserve Service (ECRS), then the Ancillary Service Resource Responsibility for ECRS shall be set to the Resource's QSE-assigned ECRS responsibility in the COP.

[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) The QSE for a Quick Start Generation Resource (QSGR) that is available for deployment by SCED and awarding of ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve (Non-Spin), if qualified and capable, shall set the COP Resource Status to OFFQS, and the COP Low Sustained Limit (LSL) and COP HSL values to the expected sustainable LSL and HSL for the QSGR for the hour.

(2) The QSGR that is available for deployment by SCED shall telemeter a Resource Status of OFFQS and a LSL of zero prior to receiving a deployment instruction from SCED. This status is necessary in order for SCED to recognize that the Resource can be Dispatched. The status of the breaker shall be open and the output of the Resource shall be zero in order for the State Estimator to correctly assess the state of the system. After being deployed for energy from SCED, the Resource shall telemeter an LSL equal to or less than the Resource's actual output until the Resource has ramped to its physical LSL. After reaching its physical LSL, the QSGR shall telemeter an LSL that reflects its physical LSL. The QSGR that is providing Off-Line Non-Spin shall always telemeter an Ancillary Service Resource Responsibility for Non-Spin to reflect the Resource's Non-

Spin obligation and shall always telemeter an Ancillary Service Schedule for Non-Spin of zero to make the capacity available for SCED.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) The QSGR that is available for deployment by SCED and awarding of ECRS and Non-Spin, if qualified and capable, shall telemeter a Resource Status of OFFQS and a LSL of zero prior to receiving a deployment instruction from SCED. This status is necessary in order for SCED to recognize that the Resource can be Dispatched and/or awarded ECRS and Non-Spin. The status of the breaker shall be open and the output of the Resource shall be zero in order for the State Estimator to correctly assess the state of the system. After being deployed for energy from SCED, the Resource shall telemeter an LSL equal to or less than the Resource's actual output until the Resource has ramped to its physical LSL. After reaching its physical LSL, the QSGR shall telemeter an LSL that reflects its physical LSL.

(3) A QSGR with a telemeter breaker status of open and a telemeter Resource Status OFFQS shall not provide Regulation Service or Responsive Reserve (RRS).

(4) ERCOT shall adjust the QSGR's Mitigated Offer Cap (MOC) curve as described in Section 4.4.9.4.1, Mitigated Offer Cap.

(5) For a QSGR that is physically Off-Line, the Resource Entity shall submit a Normal Ramp Rate curve and Emergency Ramp Rate curve indicating QSGR's ability to reach its ten-minute tested output from zero output in five minutes. This is necessary to prevent SCED from deploying multiple QSGRs due to ramp limitation in the first five minutes after being Dispatched by SCED. QSGRs shall be exempt from Base Point Deviation Charges as described in Section 6.6.5.3, Resources Exempt from Deviation Charges.

[NPRR1007: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(5) For a QSGR that is physically Off-Line, the Resource Entity shall submit a Normal Ramp Rate curve and Emergency Ramp Rate curve indicating QSGR's ability to reach its ten-minute tested output from zero output in five minutes. This is necessary to prevent SCED from deploying multiple QSGRs due to ramp limitation in the first five minutes after being Dispatched by SCED. QSGRs shall be exempt from Set Point Deviation Charges as described in Section 6.6.5.3, Resources Exempt from Deviation Charges.

(6) Any hour in which the QSE for the QSGR has shown the Resource as available for SCED Dispatch as described in this Section 3.8.3 is considered a QSE-Committed Interval.

(7) QSEs must submit and maintain an Energy Offer Curve for their QSGRs for all hours in which the COP Resource Status is submitted as OFFQS. If a valid Energy Offer Curve or an Output Schedule does not exist for any QSGR for which a Resource Status of OFFQS is telemetered at the end of the Adjustment Period, then ERCOT shall notify the QSE and set the Output Schedule equal to the then-current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period. For use as SCED inputs, ERCOT shall create proxy Energy Offer Curves for the Resource as described in paragraph (4) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(8) Other than for the potential decommitment of a QSGR as described in Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process, following a SCED QSGR deployment, the QSGR is expected to follow the SCED Base Points.

3.8.3.1 Quick Start Generation Resource Decommitment Decision Process

(1) For purposes of determining whether SCED needs a QSGR to continue to generate per paragraph (3) of Section 6.6.9, Emergency Operations Settlement, the QSE representing the QSGR shall telemeter an LSL of zero for at least one but no more than two non-consecutive SCED executions in each Operating Hour during which the QSGR is operating with a SCED Base Point equal to its registered LSL and shall telemeter Normal and Emergency Ramp Rates indicating that the QSGR can be Dispatched to zero output in a single SCED interval.

(a) If the SCED issued Base Point for the QSGR is non-zero in the interval where a zero LSL has been telemetered by the QSE, then the QSGR is deemed needed by SCED and the QSE shall immediately resume telemetering an LSL equal to the physical LSL and continue to operate the unit following subsequent Base Points.

(b) If the Base Point is zero, then the QSE will decommit the QSGR using normal operating practices.

(c) If at any point during the period in which the QSGR is in SHUTDOWN mode, the QSGR Locational Marginal Price (LMP) is greater than or equal to the Energy Offer Curve price, capped per Section 4.4.9.4.1, Mitigated Offer Cap, the QSE may reverse the decommitment process, if possible and make the QSGR available for SCED following normal operating practices.

3.8.4 Generation Resources Operating in Synchronous Condenser Fast-Response Mode

(1) A QSE is considered to have performed for the amount of its RRS obligation for the MW amount provided by a Generation Resource operating in synchronous condenser fast-response mode and triggered by an under-frequency relay device at the frequency set point specified in paragraph (3)(c) of Section 3.18, Resource Limits in Providing Ancillary Service, without corresponding RRS deployment by ERCOT. This provision

applies only for the duration when RRS MW is deployed by automatic under-frequency relay action.

3.8.5 Energy Storage Resources

(1) The Resource Entity and QSE representing an Energy Storage Resource (ESR) which is jointly registered with ERCOT as a Generation Resource and a Controllable Load Resource, pursuant to paragraph (6) of Section 16.5, Registration of a Resource Entity, are responsible for following all requirements in these Protocols associated with Generation Resources and Controllable Load Resources.

[NPRR1002: Replace paragraph (1) above with the following upon system implementation:] (1) For the purposes of all ERCOT Protocols and Other Binding Documents, all requirements that apply to Generation Resources and Controllable Load Resources shall be understood to apply to Energy Storage Resources (ESRs) to the same extent, except where the Protocols explicitly provide otherwise.

(2) A QSE representing an ESR may update the telemetered HSL and/or Maximum Power Consumption (MPC) for the ESR in Real-Time to ensure the ability to meet the ESR's full Ancillary Service Resource Responsibility for the current Operating Hour. This provision only applies when the MOC for an ESR is set at the System-Wide Offer Cap (SWCAP) pursuant to paragraph (1)(b) of Section 4.4.9.4.1, Mitigated Offer Cap.

[NPRR1075: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

(3) A QSE representing an ESR may update the telemetered HSL and/or MPC for the ESR in Real-Time to reflect state of charge limitations.

[NPRR1075: Replace paragraph (3) above with the following upon system implementation of NPRR1014:] (3) A QSE representing an ESR may update the telemetered HSL and/or LSL for the ESR in Real-Time to reflect state of charge limitations.

(4) A QSE representing an ESR co-located with a Generation Resource may reduce the telemetered MPC of the Controllable Load Resource modeled to represent the charging side of the ESR when self-charging using output from the Generation Resource. Such reduction in MPC shall be equal to the MW level of self-charge.

[NPRR1075: Replace paragraph (4) above with the following upon system implementation of NPRR1014:]

(4) A QSE representing an ESR co-located with a Generation Resource may update the telemetered LSL of the ESR when self-charging (using output from the Generation Resource). The updated LSL shall be equal to the MW level of self-charge.

3.8.6 Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)

(1) As a condition for the interconnection of a DGR or DESR, the affected Resource Entity, after consultation with the relevant Distribution Service Provider (DSP), shall provide documentation from the DSP to ERCOT stating that the interconnecting distribution circuit will not be disconnected as part of an Energy Emergency Alert (EEA) Level 3, an under-frequency Load shedding event, or an under-voltage Load shedding event, unless required for DSP local system maintenance or during a DSP local system emergency.

(a) If a DSP subsequently determines that any circuit to which a DGR or DESR is interconnected will need to be disconnected during these Load shedding events, or that a DGR or DESR will need to be moved to a circuit that will be disconnected during these Load shedding events:

(i) The DSP shall promptly notify the designated contact for the DGR or DESR;

(ii) The Resource Entity shall promptly notify ERCOT of this fact via the Resource Registration process; and

(iii) The DGR or DESR will immediately be disqualified from offering to provide any Ancillary Service.

(b) Upon receiving notification from the DSP that the DGR or DESR is no longer subject to disconnection during any of these Load shedding events, and that no known system limitations or changes have occurred that would inhibit the DGR or DESR from complying with Ancillary Service performance requirements, the Resource Entity for the DGR or DESR shall notify ERCOT of this fact via the Resource Registration process and will, at that time, be eligible to offer to provide Ancillary Services if the Resource is otherwise qualified to do so.

(2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or DESR, the interconnecting DSP will evaluate the proposed conversion and will determine whether it is electrically and operationally feasible. If the interconnecting DSP determines that the conversion is not electrically or operationally feasible, the DSP may disallow the conversion.

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

(2) For a proposed conversion of an existing Settlement Only Distribution Generator (SODG) to a DGR or for a proposed conversion of an existing Settlement Only Distribution Energy Storage System (SODESS) to a DESR, the interconnecting DSP will evaluate the proposed conversion and will determine whether it is electrically and operationally feasible. If the interconnecting DSP determines that the conversion is not electrically or operationally feasible, the DSP may disallow the conversion.

(3) The Resource Node for a DGR or DESR shall be fixed at a single Electrical Bus in the ERCOT Network Operations Model.

(a) If a DSP determines that a topology change has altered, or is expected to alter, the electrical path connecting the DGR or DESR to the ERCOT Transmission Grid for a period longer than 60 days:

(i) The DSP shall promptly notify the interconnecting Transmission Service Provider (TSP) and the designated contact for the DGR or DESR, and the interconnecting TSP shall notify ERCOT; and

(ii) The Resource Entity shall submit a change request to ERCOT via the Resource Registration process.

[NPRR1026 and NPRR1077: Insert applicable portions of Section 3.8.7 below upon system implementation:]

3.8.7 Self-Limiting Facility

(1) A Resource Entity or Interconnecting Entity (IE) for a Self-Limiting Facility may establish a MW Injection or MW Withdrawal limit by submitting an attestation in a form designated by ERCOT through the Resource Registration process. The Resource Entity or IE shall simultaneously provide a copy of the attestation to the interconnecting Transmission and/or Distribution Service Provider (TDSP). All registered generators or Energy Storage Systems (ESSs) within a Self-Limiting Facility shall be represented by a single Resource Entity and a single QSE.

(2) A Self-Limiting Facility shall not inject or withdraw power in excess of its established MW Injection limit or its established MW Withdrawal limit.

(3) On a monthly basis, ERCOT will report to the Reliability Monitor and IMM any instance where a Self-Limiting Facility's actual MW Injections exceeded the MW Injection limit or where actual MW Withdrawals exceeded the MW Withdrawal limit established in the Resource Registration data for the Self-Limiting Facility, based on the telemetry of the injection and withdrawal values provided by the QSE for the registered

generator or ESS in the Self-Limiting Facility, as described in Section 3.9.1, Current Operating Plan (COP) Criteria, and in Section 6.5.5.2, Operational Data Requirements, or based on the meter data at the Point of Interconnection (POI) or Point of Common Coupling (POCC) for the Self-Limiting Facility.

(4) If requested by ERCOT, the relevant QSE shall provide meter data to confirm whether the established limits for a Self-Limiting Facility were violated.

(5) If ERCOT determines that a Self-Limiting Facility connected at transmission voltage has exceeded either its MW Injection limit or its MW Withdrawal limit established in the Resource Registration data by more than the greater of 5 MW or 3% of the limit, the Self-Limiting Facility shall submit a new generation interconnection request based on the installed MW capacity of the individual Resource(s) and shall deregister as a Self-Limiting Facility at the completion of the generation interconnection process. The Self-Limiting Facility shall be subject to the established MW Injection limit and any established MW Withdrawal limit until the generation interconnection process has been completed.

(6) A Distribution Service Provider (DSP) may limit injections and withdrawals from any Generation Resource, Settlement Only Generator (SOG), or ESR based on Resource Registration data and the interconnection agreement between the DSP and the IE or Resource Entity. In that case, the IE or Resource Entity shall submit the attestation required by paragraph (1) above, and shall be considered a Self-Limiting Facility.

(7) If ERCOT determines that a Self-Limiting Facility connected at distribution voltage has exceeded either its MW Injection limit or its MW Withdrawal limit established in the Resource Registration data, the Self-Limiting Facility shall submit a new generation interconnection request based on the installed MW capacity of the individual Resource(s) and shall be deregistered as a Self-Limiting Facility at the completion of the generation interconnection process. The Self-Limiting Facility shall be subject to any MW Injection or MW Withdrawal limit until the generation interconnection process has been completed.

(8) The interconnecting TDSP, at its sole discretion, may use relaying to ensure a Self-Limiting Facility does not inject or withdraw energy in excess of its MW Injection or MW Withdrawal limits in order to protect the TDSP's limiting element(s).

[NPRR1029 and NPRR1111: Insert applicable portions of Section 3.8.8 below upon system implementation for NPRR1029; or upon system implementation of SCR819 for NPRR1111:]

3.8.8 DC-Coupled Resources

(1) A DC-Coupled Resource shall be treated in the same manner as an Energy Storage Resource (ESR) for the purposes of determining Set Point Deviation Charges, as described in Section 6.6.5, Set Point Deviation Charge, and Energy Storage Resource

Energy Deployment Performance (ESREDP), as described in Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, under one of the following conditions:

(a) The Resource was awarded Ancillary Service;

(b) The Resource's instantaneous MW Injection or MW Withdrawal includes non-zero MW from the ESS component of the DC-Coupled Resource; or

(c) The Resource's telemetered HSL or LSL includes the ESS capability.

(2) At all other times, a DC-Coupled Resource shall be treated in the same manner as an IRR for the purposes of determining Set Point Deviation Charges, as described in Section 6.6.5, and ESREDP, as described in Section 8.1.1.4.1.

(3) A QSE representing a DC-Coupled Resource that does not meet any of the conditions in paragraph (1) above:

(a) Shall set the Resource's telemetered HSL equal to the current net output capability of the intermittent renewable generation component of the DC-Coupled Resource; and

(b) Shall set the Resource's output at or below the SCED Base Point telemetered by ERCOT if the Resource receives a flag indicating that SCED has dispatched it below the Resource's HDL used by SCED or that it has been instructed not to exceed its Base Point.

3.9 Current Operating Plan (COP)

(1) Each Qualified Scheduling Entity (QSE) that represents a Resource must submit a Current Operating Plan (COP) under this Section.

(2) ERCOT shall use the information provided in the COP to calculate the High Ancillary Service Limit (HASL) and Low Ancillary Service Limit (LASL) for each Resource for the Reliability Unit Commitment (RUC) processes.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) ERCOT shall use the information provided in the COP to calculate operating limits and Ancillary Service capabilities for each Resource for the Reliability Unit Commitment (RUC) processes.

(3) ERCOT shall monitor the accuracy of each QSE's COP as outlined in Section 8, Performance Monitoring.

(4) A QSE must notify ERCOT that it plans to have a Resource On-Line by means of the COP using the Resource Status codes listed in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria. The QSE must show the Resource as On-Line with a Resource Status of ONRUC, indicating a RUC process committed the Resource for all RUC-Committed Intervals. A QSE may only use a RUC-committed Resource during that Resource's RUC-Committed Interval to meet the QSE's Ancillary Service Supply Responsibility if the Resource has been committed by the RUC process to provide Ancillary Service.

(5) To reflect changes to a Resource's capability, each QSE shall report by exception, changes to the COP for all hours after the Operating Period through the rest of the Operating Day.

(6) When a QSE updates its COP to show changes in Resource Status, the QSE shall update for each On-Line Resource, either an Energy Offer Curve under Section 4.4.9, Energy Offers and Bids, or Output Schedule under Section 6.4.2, Output Schedules.

(7) Each QSE, including QSEs representing Reliability Must-Run (RMR) Units, Firm Fuel Supply Service Resources (FFSSRs), or Black Start Resources, shall submit a revised COP reflecting changes in Resource availability as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change.

(8) Each QSE representing a Qualifying Facility (QF) must submit a Low Sustained Limit (LSL) that represents the minimum energy available, in MW, from the unit for economic dispatch based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

(9) When ERCOT issues a communication in the form of an Operating Condition Notice (OCN), Advisory, Watch, or Emergency Notice due to forecasted or actual cold or hot weather, for each Generation Resource and Energy Storage Resource (ESR) a QSE represents, the QSE shall update the COP, Real-Time telemetry, and Outage or derate reporting to reflect any Resource-specific operating limitations based on: (i) capability and availability; (ii) fuel supply or inventory concerns, including fuel switching capabilities; or (iii) environmental constraints and the impact on the Generation Resource or ESR due to the weather conditions. QSEs shall provide these updates in accordance with Sections 3.1.4, Communications Regarding Resource and Transmission Facility Outages; 3.10.7.5, Telemetry Requirements; 3.9, Current Operating Plan (COP); 3.9.1, Current Operating Plan (COP) Criteria; and Nodal Operating Guide Section 7.3, Telemetry.

3.9.1 Current Operating Plan (COP) Criteria

(1) Each QSE that represents a Resource must submit a COP to ERCOT that reflects expected operating conditions for each Resource for each hour in the next seven Operating Days.

(2) Each QSE that represents a Resource shall update its COP reflecting changes in availability of any Resource as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change. Each QSE shall timely update its COP unless in the reasonable judgment of the QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment. The QSE is excused from updating the COP only for so long as the undue threat to safety, undue risk of bodily harm, or undue damage to equipment exists. The time for updating the COP begins once the undue threat to safety, undue risk of bodily harm, or undue damage to equipment no longer exists.

(3) The Resource capacity in a QSE's COP must be sufficient to supply the Ancillary Service Supply Responsibility of that QSE.

[NPRR1007, NPRR1014, and NPRR1029: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(3) Each QSE that represents a Resource shall update its COP to reflect the ability of the Resource to provide each Ancillary Service by product and sub-type.

(4) Load Resource COP values may be adjusted to reflect Distribution Losses in accordance with Section 8.1.1.2, General Capacity Testing Requirements.

(5) A COP must include the following for each Resource represented by the QSE:

(a) The name of the Resource;

(b) The expected Resource Status:

(i) Select one of the following for Generation Resources synchronized to the ERCOT System that best describes the Resource's status. Unless otherwise provided below, these Resource Statuses are to be used for COP and/or Real-Time telemetry purposes, as appropriate.

(A) ONRUC – On-Line and the hour is a RUC-Committed Hour;

(B) ONREG – On-Line Resource with Energy Offer Curve providing Regulation Service;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (B) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(C) ON – On-Line Resource with Energy Offer Curve;

(D) ONDSR – On-Line Dynamically Scheduled Resource (DSR);

[NPRR1000: Delete item (D) above upon system implementation and renumber accordingly.]

(E) ONOS – On-Line Resource with Output Schedule;

(F) ONOSREG – On-Line Resource with Output Schedule providing Regulation Service;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (F) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(G) ONDSRREG – On-Line DSR providing Regulation Service;

[NPRR1000, NPRR1007, NPRR1014, and NPRR1029: Delete item (G) above upon system implementation for NPRR1000, NPRR1014, or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; and renumber accordingly.]

(H) FRRSUP – Available for Dispatch of Fast Responding Regulation Service (FRRS). This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (H) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 and NPRR1029; and renumber accordingly.]

(I) ONTEST – On-Line blocked from Security-Constrained Economic Dispatch (SCED) for operations testing (while ONTEST, a Generation Resource may be shown on Outage in the Outage Scheduler);

(J) ONEMR – On-Line EMR (available for commitment or dispatch only for ERCOT-declared Emergency Conditions; the QSE may appropriately set LSL and High Sustained Limit (HSL) to reflect operating limits);

(K) ONRR – On-Line as a synchronous condenser providing Responsive Reserve (RRS) but unavailable for Dispatch by SCED and available for commitment by RUC;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (K) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(L) ONECRS – On-Line as a synchronous condenser providing ERCOT Contingency Response Service (ECRS) but unavailable for Dispatch by SCED and available for commitment by RUC;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (L) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(M) ONOPTOUT – On-Line and the hour is a RUC Buy-Back Hour;

(N) SHUTDOWN – The Resource is On-Line and in a shutdown sequence, and has no Ancillary Service Obligations other than Off-Line Non-Spinning Reserve (Non-Spin) which the Resource will provide following the shutdown. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (N) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(N) SHUTDOWN – The Resource is On-Line and in a shutdown sequence, and is not eligible for an Ancillary Service award. This Resource Status is only to be used for Real-Time telemetry purposes;

(O) STARTUP – The Resource is On-Line and in a start-up sequence and has no Ancillary Service Obligations. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (O) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(O) STARTUP – The Resource is On-Line and in a start-up sequence and is not eligible for an Ancillary Service award, unless coming On-Line in response to a manual deployment of ERCOT Contingency Reserve Service (ECRS) or Non-Spinning Reserve (Non-Spin). This Resource Status is only to be used for Real-Time telemetry purposes;

(P) OFFQS – Off-Line but available for SCED deployment. Only qualified Quick Start Generation Resources (QSGRs) may utilize this status;

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (P) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(P) OFFQS – Off-Line but available for SCED deployment and to provide ECRS and Non-Spin, if qualified and capable. Only qualified Quick Start Generation Resources (QSGRs) may utilize this status;

(Q) ONFFRRRS – Available for Dispatch of RRS when providing Fast Frequency Response (FFR) from Generation Resources. This Resource Status is only to be used for Real-Time telemetry purposes. A Resource with this Resource Status may also be providing Ancillary Services other than FFR; and

[NPRR1007, NPRR1014, and NPRR1029: Delete item (Q) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

[NPRR1007, NPRR1014, and NPRR1029: Insert item (K) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(K) ONSC – Resource is On-Line operating as a synchronous condenser and available to provide Responsive Reserve (RRS) and ECRS, if qualified and capable, and for commitment by RUC, but is unavailable for Dispatch by SCED. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution; and

(R) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or for participating in Ancillary Services. This Resource Status is only to be used for Real-Time telemetry purposes. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution.

[NPRR1007, NPRR1014, and NPRR1029: Replace item (R) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(R) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or Ancillary Service awards. This Resource Status is only to be used for Real-Time telemetry purposes. For SCED, Resource Base Points will be set equal to the telemetered net real power of the Resource available at the time of the SCED execution.

(ii) Select one of the following for Off-Line Generation Resources not synchronized to the ERCOT System that best describes the Resource's status. These Resource Statuses are to be used for COP and/or Real-Time telemetry purposes, as appropriate.

(A) OUT – Off-Line and unavailable, or not connected to the ERCOT System and operating in a Private Microgrid Island (PMI);

(B) OFFNS – Off-Line but reserved for Non-Spin;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (B) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(C) OFF – Off-Line but available for commitment in the Day-Ahead Market (DAM) and RUC;

[NPRR1007, NPRR1014, and NPRR1029: Replace item (C) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(B) OFF – Off-Line but available for commitment in the Day-Ahead Market (DAM), RUC, and providing Non-Spin, if qualified and capable;

(D) EMR – Available for commitment as a Resource contracted by ERCOT under Section 3.14.1, Reliability Must Run, or under paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority, or available for commitment only for ERCOT-declared Emergency Condition events; the QSE may appropriately set LSL and HSL to reflect operating limits;

(E) EMRSWGR – Switchable Generation Resource (SWGR) operating in a non-ERCOT Control Area, or in the case of a Combined Cycle Train with one or more SWGRs, a configuration in which one or more of the physical units in that configuration are operating in a non-ERCOT Control Area.

(iii) Select one of the following for Load Resources. Unless otherwise provided below, these Resource Statuses are to be used for COP and/or Real-Time telemetry purposes.

(A) ONRGL – Available for Dispatch of Regulation Service by Load Frequency Control (LFC) and, for any remaining Dispatchable capacity, by SCED with a Real-Time Market (RTM) Energy Bid;

(B) FRRSUP – Available for Dispatch of FRRS by LFC and not Dispatchable by SCED. This Resource Status is only to be used for Real-Time telemetry purposes;

(C) FRRSDN – Available for Dispatch of FRRS by LFC and not Dispatchable by SCED. This Resource Status is only to be used for Real-Time telemetry purposes;

(D) ONCLR – Available for Dispatch as a Controllable Load Resource by SCED with an RTM Energy Bid;

(E) ONRL – Available for Dispatch of RRS or Non-Spin, excluding Controllable Load Resources. A Load Resource, excluding Controllable Load Resources, may not provide ECRS with this Resource Status;

[NPRR1007, NPRR1014, and NPRR1029: Delete items (A)-(E) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(F) ONECL – Available for Dispatch of ECRS or available for Dispatch of ECRS and RRS simultaneously, excluding Controllable Load Resources;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (F) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029; and renumber accordingly.]

(G) OUTL – Not available;

(H) ONFFRRRSL – Available for Dispatch of RRS when providing FFR, excluding Controllable Load Resources. This Resource Status is only to be used for Real-Time telemetry purposes;

[NPRR1007, NPRR1014, and NPRR1029: Delete item (H) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029.]

[NPRR1007, NPRR1014, NPRR1029: Insert item (B) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(B) ONL – On-Line and available for Dispatch by SCED or providing Ancillary Services.

[NPRR1014 or NPRR1029: Insert applicable portions of paragraph (iv) below upon system implementation:]

(iv) Select one of the following for Energy Storage Resources (ESRs). Unless otherwise provided below, these Resource Statuses are to be used for COP and Real-Time telemetry purposes:

(A) ON – On-Line Resource with Energy Bid/Offer Curve;

(B) ONOS – On-Line Resource with Output Schedule;

(C) ONTEST – On-Line blocked from SCED for operations testing (while ONTEST, an Energy Storage Resource (ESR) may be shown on Outage in the Outage Scheduler);

(D) ONEMR – On-Line EMR (available for commitment or dispatch only for ERCOT-declared Emergency Conditions; the QSE may appropriately set LSL and High Sustained Limit (HSL) to reflect operating limits);

(E) ONHOLD – Resource is On-Line but temporarily unavailable for Dispatch by SCED or Ancillary Service awards. ESRs shall not be discharging into or charging from the grid. This Resource Status is only to be used for Real-Time telemetry purposes; and

(F) OUT – Off-Line and unavailable, or not connected to the ERCOT System and operating in a Private Microgrid Island (PMI);

(c) The HSL;

(i) For Load Resources other than Controllable Load Resources, the HSL should equal the expected power consumption;

[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (ii) below upon system implementation:]

(ii) For ESRs, the HSL may be negative;

(d) The LSL;

(i) For Load Resources other than Controllable Load Resources, the LSL should equal the expected Low Power Consumption (LPC);

[NPRR1014 and NPRR1029: Insert applicable portions of paragraph (ii) below upon system implementation:]

(ii) For ESRs, the LSL may be positive;

(e) The High Emergency Limit (HEL);

(f) The Low Emergency Limit (LEL); and

(g) Ancillary Service Resource Responsibility capacity in MW for:

[NPRR1007, NPRR1014, and NPRR1029: Replace applicable portions of item (g) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(g) Ancillary Service capability in MW for each product and sub-type.

(i) Regulation Up Service (Reg-Up);

(ii) Regulation Down Service (Reg-Down);

(iii) RRS;

(iv) ECRS; and

(v) Non-Spin.

[NPRR1007, NPRR1014, and NPRR1029: Delete items (i)-(v) above upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029.]

(6) For Combined Cycle Generation Resources, the above items are required for each operating configuration. In each hour only one Combined Cycle Generation Resource in a Combined Cycle Train may be assigned one of the On-Line Resource Status codes described above.

(a) During a RUC study period, if a QSE's COP reports multiple Combined Cycle Generation Resources in a Combined Cycle Train to be On-Line for any hour, then until the QSE corrects its COP, the On-Line Combined Cycle Generation Resource with the largest HSL is considered to be On-Line and all other Combined Cycle Generation Resources in the Combined Cycle Train are considered to be Off-Line. Furthermore, until the QSE corrects its COP, the Off-Line Combined Cycle Generation Resources as designated through the application of this process are ineligible for RUC commitment or de-commitment Dispatch Instructions.

(b) For any hour in which QSE-submitted COP entries are used to determine the initial state of a Combined Cycle Generation Resource for a DAM or Day-Ahead Reliability Unit Commitment (DRUC) study and the COP shows multiple Combined Cycle Generation Resources in a Combined Cycle Train to be in an On-Line Resource Status, then until the QSE corrects its COP, the On-Line Combined Cycle Generation Resource that has been On-Line for the longest time from the last recorded start by ERCOT systems, regardless of the reason for the start, combined with the COP Resource Status for the remaining hours of the current Operating Day, is considered to be On-Line at the start of the DRUC study period and all other COP-designated Combined Cycle Generation Resources in the Combined Cycle Train are considered to be Off-Line.

(c) ERCOT systems shall allow only one Combined Cycle Generation Resource in a Combined Cycle Train to offer Off-Line Non-Spin in the DAM or Supplemental Ancillary Services Market (SASM).

[NPRR1007, NPRR1014, and NPRR1029: Replace paragraph (c) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1014 or NPRR1029:]

(c) ERCOT systems shall allow only one Combined Cycle Generation Resource in a Combined Cycle Train to offer Off-Line Non-Spin in the DAM or SCED.

(i) If there are multiple Non-Spin offers from different Combined Cycle Generation Resources in a Combined Cycle Train, then prior to execution of the DAM, ERCOT shall select the Non-Spin offer from the Combined Cycle Generation Resource with the highest HSL for consideration in the DAM and ignore the other offers.

(ii) Combined Cycle Generation Resources offering Off-Line Non-Spin must be able to transition from the shutdown state to the offered Combined Cycle Generation Resource On-Line state and be capable of ramping to the full amount of the Non-Spin offered.

(d) The DAM and RUC shall honor the registered hot, intermediate or cold Startup Costs for each Combined Cycle Generation Resource registered in a Combined Cycle Train when determining the transition costs for a Combined Cycle Generation Resource. In the DAM and RUC, the Startup Cost for a Combined Cycle Generation Resource shall be determined by the positive transition cost from the On-Line Combined Cycle Generation Resource within the Combine Cycle Train or from a shutdown condition, whichever ERCOT determines to be appropriate.

(7) ERCOT may accept COPs only from QSEs.

(8) For the first 168 hours of the COP, ERCOT will update the HSL values for Wind-powered Generation Resources (WGRs) with the most recently updated Short-Term Wind Power Forecast (STWPF), and the HSL values for PhotoVoltaic Generation Resources (PVGRs) with the most recently updated Short-Term PhotoVoltaic Power Forecast (STPPF). ERCOT will notify the QSE via an Extensible Markup Language (XML) message each time COP HSL values are updated with the forecast values. A QSE representing a WGR may override the STWPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STWPF provided by ERCOT; a QSE representing a PVGR may override the STPPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STPPF provided by ERCOT.

[NPRR1029: Replace paragraph (8) above with the following upon system implementation:]

(8) For the first 168 hours of the COP, ERCOT will update the HSL values for Wind-powered Generation Resources (WGRs) with the most recently updated Short-Term

Wind Power Forecast (STWPF), and the HSL values for PhotoVoltaic Generation Resources (PVGRs) with the most recently updated Short-Term PhotoVoltaic Power Forecast (STPPF). A QSE representing a DC-Coupled Resource shall provide the capacity value of the Energy Storage System (ESS) that is included in the HSL of the DC-Coupled Resource, and ERCOT will update the DC-Coupled Resource's HSL with the sum of the forecasts of the intermittent renewable generation component and the QSE-submitted value for the ESS component. ERCOT will notify the QSE via an Extensible Markup Language (XML) message each time COP HSL values are updated with the forecast values. A QSE representing a WGR may override the STWPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STWPF provided by ERCOT; a QSE representing a PVGR may override the STPPF HSL value but must submit an HSL value that is less than or equal to the amount for that Resource from the most recent STPPF provided by ERCOT. A QSE representing a DC-Coupled Resource may override the COP HSL value with a value that is lower than the ERCOT-populated value, and may override with a value that is higher than the ERCOT-populated value if the ESS component of the DC-Coupled Resource can support the higher value.

(9) A QSE representing a Generation Resource that is not actively providing Ancillary Services or is providing Off-Line Non-Spin that the Resource will provide following the shutdown, may only use a Resource Status of SHUTDOWN to indicate to ERCOT through telemetry that the Resource is operating in a shutdown sequence or a Resource Status of ONTEST to indicate in the COP and through telemetry that the Generation Resource is performing a test of its operations either manually dispatched by the QSE or by ERCOT as part of the test. A QSE representing a Generation Resource that is not actively providing Ancillary Services may only use a Resource Status of STARTUP to indicate to ERCOT through telemetry that the Resource is operating in a start-up sequence requiring manual control and is not available for Dispatch.

(10) If a QSE has not submitted a valid COP for any Generation Resource for any hour in the DAM or RUC Study Period, then the Generation Resource is considered to have a Resource Status as OUT thus not available for DAM awards or RUC commitments for those hours.

(11) If a COP is not available for any Resource for any hour from the current hour to the start of the DAM period or RUC study, then the Resource Status for those hours are considered equal to the last known Resource Status from a previous hour's COP or from telemetry as appropriate for that Resource.

(12) A QSE representing a Resource may only use the Resource Status code of EMR for a Resource whose operation would have impacts that cannot be monetized and reflected through the Resource's Energy Offer Curve or recovered through the RUC make-whole process or if the Resource has been contracted by ERCOT under Section 3.14.1 or under paragraph (4) of Section 6.5.1.1. If ERCOT chooses to commit an Off-Line unit with EMR Resource Status that has been contracted by ERCOT under Section 3.14.1 or under

paragraph (4) of Section 6.5.1.1, the QSE shall change its Resource Status to ONRUC. Otherwise, the QSE shall change its Resource Status to ONEMR.

(13) A QSE representing a Resource may use the Resource Status code of ONEMR for a Resource that is:

(a) On-Line, but for equipment problems it must be held at its current output level until repair and/or replacement of equipment can be accomplished; or

(b) A hydro unit.

(14) A QSE operating a Resource with a Resource Status code of ONEMR may set the HSL and LSL of the unit to be equal to ensure that SCED does not send Base Points that would move the unit.

(15) A QSE representing a Resource may use the Resource Status code of EMRSWGR only for an SWGR.

[NPRR1026: Insert paragraph (16) below upon system implementation:]

(16) A QSE representing a Self-Limiting Facility must ensure that the sum of the COP HSL/LSL and the sum of the telemetered HSL/LSL submitted for each Resource within the Self-Limiting Facility do not exceed either the limit on MW Injection or the limit on the MW Withdrawal established for the Self-Limiting Facility.

[NPRR1029: Insert paragraph (16) below upon system implementation:]

(16) A QSE representing a DC-Coupled Resource shall not submit an HSL that exceeds the inverter rating or the sum of the nameplate ratings of the generation component(s) of the Resource.

3.9.2 Current Operating Plan Validation

(1) ERCOT shall verify that each COP, on its submission, complies with the criteria described in Section 3.9.1, Current Operating Plan (COP) Criteria. ERCOT shall notify the QSE by means of the Messaging System if the QSE's COP fails to comply with the criteria described in Section 3.9.1 and this Section 3.9.2 for any reason. The QSE must then resubmit the COP within the appropriate market timeline.

(2) ERCOT may reject a COP that does not meet the criteria described in Section 3.9.1.

(3) If a Resource is designated in the COP to provide Ancillary Service, then ERCOT shall verify that the COP complies with Section 3.16, Standards for Determining Ancillary Service Quantities. The Ancillary Service Supply Responsibilities as indicated in the

Ancillary Service Resource Responsibility submitted immediately before the end of the Adjustment Period are physically binding commitments for each QSE for the corresponding Operating Period.

(4) ERCOT shall notify the QSE if the sum of the Ancillary Service capacity designated in the COP for each hour, by service type, is less than the QSE's Ancillary Service Supply Responsibility for each service type for that hour. If the QSE does not correct the deficiency within one hour after receiving the notice from ERCOT, then ERCOT shall follow the procedures outlined in Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency.

(5) A QSE may change Ancillary Service Resource designations by changing its COP, subject to Section 6.4.9.1.

(6) If ERCOT determines that it needs more Ancillary Service during the Adjustment Period, then the QSE's allocated portion of the additional Ancillary Service may be self-arranged.

[NPRR1007: Delete paragraphs (3)-(6) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(7) ERCOT systems must be able to detect a change in status of a Resource shown in the COP and must provide notice to ERCOT operators of changes that a QSE makes to its COP.

(8) A QSE representing a Resource that has an Energy Offer Curve valid for an hour of the COP may not designate a Resource Status of ONOS or ONDSR for that hour for that Resource.

[NPRR1000: Replace paragraph (8) above with the following upon system implementation:]

(8) A QSE representing a Resource that has an Energy Offer Curve valid for an hour of the COP may not designate a Resource Status of ONOS for that hour for that Resource.

3.10 Network Operations Modeling and Telemetry

(1) ERCOT shall use the physical characteristics, ratings, and operational limits of all Transmission Elements of the ERCOT Transmission Grid and other information from the Transmission Service Providers (TSPs) and Resource Entities to specify limits within which the transmission network is defined in the network models made available to Market Participants as noted below and used to operate the ERCOT Transmission Grid as updated. If a Private Use Network is not registered as a Resource Entity, then ERCOT

shall use equivalent model data provided by TSPs, if available, that represents the Private Use Network in the TSPs' modeling systems for use in the Network Operations Model.

[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 use the physical characteristics, ratings, and operational limits of all Transmission Elements of the ERCOT Transmission Grid and other information from Transmission Service Providers (TSPs), Direct Current Tie Operators (DCTOs), and Resource Entities to specify limits within which the transmission network is defined in the network models made available to Market Participants as noted below and used to operate the ERCOT Transmission Grid as updated. If a Private Use Network is not registered as a Resource Entity, then ERCOT shall use equivalent model data provided by TSPs, if available, that represents the Private Use Network in the TSPs' modeling systems for use in the Network Operations Model.

(2) Because the ERCOT market requires accurate modeling of Transmission Elements in order to send accurate Base Points and pricing signals to Market Participants, ERCOT shall manage the Network Operations Model. By providing Base Points and pricing signals by Electrical Bus to Market Participants, the Market Participants' responses result in power flows on all Transmission Elements that ERCOT must monitor and, if necessary for reliability reasons, manage within ratings provided by the TSP and Resource Entity and limits assigned by ERCOT including Generic Transmission Limits (GTLs) as may be defined in Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

[NPRR857: Replace paragraph (2) 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:]

(2) Because the ERCOT market requires accurate modeling of Transmission Elements in order to send accurate Base Points and pricing signals to Market Participants, ERCOT shall manage the Network Operations Model. By providing Base Points and pricing signals by Electrical Bus to Market Participants, the Market Participants' responses result in power flows on all Transmission Elements that ERCOT must monitor and, if necessary for reliability reasons, manage within ratings provided by each TSP, DCTO,

and Resource Entity and limits assigned by ERCOT including Generic Transmission Limits (GTLs) as may be defined in Section 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits.

(3) TSPs and Resource Entities shall provide ERCOT with equipment ratings and update the ratings as required by ERCOT. ERCOT may request TSPs and Resource Entities to provide detailed information on the methodology, including data for determination of each requested rating. ERCOT may review and comment on the methodology. ERCOT shall post all methodologies on the Market Information System (MIS) Secure Area within seven days following a change in methodology.

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

(3) Each TSP, DCTO, and Resource Entity shall provide ERCOT with equipment ratings and update the ratings as required by ERCOT. ERCOT may request that a TSP, DCTO, or Resource Entity provide detailed information on the methodology, including data for determination of each requested rating. ERCOT may review and comment on the methodology. ERCOT shall post all methodologies on the Market Information System (MIS) Secure Area within seven days following a change in methodology.

(4) ERCOT must use system ratings consistent with the ratings expected to be used during Real-Time for the system condition being modeled, including Dynamic Ratings using expected temperatures for those system conditions. For each model, ERCOT shall post ratings and the ambient temperatures used to calculate the ratings on the MIS Secure Area when the model is published.

(5) ERCOT shall use consistent information within and between the various models used by ERCOT in a manner that yields consistent results. For operational and planning models that are intended to represent the same system state the results should be consistent and the naming should be identical.

(6) ERCOT shall use a Network Operations Model Change Request (NOMCR) process to control all information entering the Network Operations Model. In order to allow for construction schedules, each NOMCR must be packaged as a single package describing any incremental changes and referencing any prerequisite NOMCRs, using an industry standard data exchange format. A package must contain a series of instructions that define the changes that need to be made to implement a network model change. ERCOT shall verify each package for completeness and accuracy prior to the period it is to be implemented.

(7) ERCOT shall use an automated process to manage the Common Information Model (CIM) compliant packages loaded into the Network Operations Model as each construction phase is completed. ERCOT shall reject any NOMCRs that are not CIM compliant. Each CIM compliant NOMCR must also be associated with commands to update the graphical displays associated with the network model modification. During the testing phase, each NOMCR must be tested for proper sequencing and its effects on downstream applications.

(8) ERCOT shall track each data submittal received from TSPs via the NOMCR process and from Resource Entities via the Resource Registration process. Resource Registration data is converted by ERCOT to the appropriate NOMCR format through implementation and final testing of the change. ERCOT shall notify each TSP and Resource Entity when the requested change is processed and implemented in accordance with Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall also provide the submitting TSP a link to a Network Operations Model containing the change for verifying the implementation of the NOMCR and associated one-line displays. ERCOT shall post all NOMCRs on the MIS Certified Area for TSPs only within five Business Days following receipt of the NOMCR, consistent with the requirements regarding ERCOT Critical Energy Infrastructure Information (ECEII) set forth in Section 1.3, Confidentiality. When posting a NOMCR, each change must be posted using the CIM data exchange format showing incremental changes to the last Network Operations Model for TSPs only, to facilitate TSPs in updating their internal network models to reflect changes made at ERCOT. For each NOMCR, ERCOT shall post on the MIS Certified Area for TSPs only the current status on the in-service date for each NOMCR, including any prerequisite NOMCRs provided by the requestor.

[NPRR857: Replace paragraph (8) 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:]

(8) ERCOT shall track each data submittal received from TSPs and DCTOs via the NOMCR process and from Resource Entities via the Resource Registration process. Resource Registration data is converted by ERCOT to the appropriate NOMCR format through implementation and final testing of the change. ERCOT shall notify each TSP, DCTO, and Resource Entity when the requested change is processed and implemented in accordance with Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall also provide the submitting TSP and DCTO a link to a Network Operations Model containing the change for verifying the implementation of the NOMCR and associated one-line displays. ERCOT shall post all NOMCRs on the MIS Certified Area for TSPs only within five Business Days following receipt of the NOMCR, consistent with the requirements regarding ERCOT Critical Energy Infrastructure Information (ECEII) set forth in Section 1.3, Confidentiality. When

posting a NOMCR, each change must be posted using the CIM data exchange format showing incremental changes to the last Network Operations Model for TSPs only, to facilitate TSPs in updating their internal network models to reflect changes made at ERCOT. For each NOMCR, ERCOT shall post on the MIS Certified Area for TSPs only the current status on the in-service date for each NOMCR, including any prerequisite NOMCRs provided by the requestor.

(9) ERCOT shall update the Network Operations Model under this Section and coordinate it with the planning models for consistency to the extent applicable.

(10) Any requestor of any changes in system topology or telemetry must receive approval from ERCOT before connecting of any associated equipment to the ERCOT Transmission Grid. ERCOT shall notify a requestor of any deficiencies in its submittal for changes in system topology or telemetry. ERCOT shall accept corrections to the submittal if the requestor has corrected any deficiencies by the required submittal date specified in Section 3.10.1. ERCOT shall post any changes to an NOMCR on the MIS Certified Area for TSPs within three Business Days of accepting corrections.

[NPRR857: Replace paragraph (10) 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:]

(10) Any requestor of any changes in system topology or telemetry must receive approval from ERCOT before connecting of any associated equipment to the ERCOT Transmission Grid. ERCOT shall notify a requestor of any deficiencies in its submittal for changes in system topology or telemetry. ERCOT shall accept corrections to the submittal if the requestor has corrected any deficiencies by the required submittal date specified in Section 3.10.1. ERCOT shall post any changes to a NOMCR on the MIS Certified Area for TSPs and DCTOs within three Business Days of accepting corrections.

(11) On receipt of the information set forth in Section 3.10.7, ERCOT System Modeling Requirements, ERCOT shall review the information and notify the requestor of any required modifications. ERCOT may, at its discretion, require changes or more details regarding the work plan for any new or relocated facilities. The requestor shall notify ERCOT and any other affected Entities as soon as practicable of any ERCOT requested changes to the work plan. The requestor shall consult with other Entities likely to be affected and shall revise the work plan, following any necessary or appropriate discussions with ERCOT and other affected Entities. ERCOT shall approve or reject the request, including any revisions made by the requestor, within 15 days of receipt of the

complete request and any revisions. Following ERCOT approval, ERCOT shall publish a summary of the revised NOMCR on the MIS Certified Area for TSPs.

[NPRR857: Replace paragraph (11) 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:]

(11) On receipt of the information set forth in Section 3.10.7, ERCOT System Modeling Requirements, ERCOT shall review the information and notify the requestor of any required modifications. ERCOT may, at its discretion, require changes or more details regarding the work plan for any new or relocated facilities. The requestor shall notify ERCOT and any other affected Entities as soon as practicable of any ERCOT requested changes to the work plan. The requestor shall consult with other Entities likely to be affected and shall revise the work plan, following any necessary or appropriate discussions with ERCOT and other affected Entities. ERCOT shall approve or reject the request, including any revisions made by the requestor, within 15 days of receipt of the complete request and any revisions. Following ERCOT approval, ERCOT shall publish a summary of the revised NOMCR on the MIS Certified Area for TSPs and DCTOs.

3.10.1 Time Line for Network Operations Model Changes

(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 Network Operations Model updates at least three months prior to the physical equipment change. 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 (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

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 (5)**	**Update Network Operations Model Production Environment**	**Target Physical Equipment included in Production Model** **Note 4**
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 interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) TSPs, DCTOs, and Resource Entities shall submit Network Operations Model updates at least three months prior to the physical equipment change. 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 (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, 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.
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) ERCOT shall only approve energization requests when the Transmission Element is satisfactorily modeled in the Network Operations Model.

(5) 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

3.10.2 Annual Planning Model

(1) For each of the next six years, ERCOT shall develop models for annual planning purposes that contain, as much as practicable, information consistent with the Network Operations Model. The "Annual Planning Model" for each of the next six years is a model of the ERCOT power system (created, approved, posted, and updated regularly by ERCOT) as it is expected to operate during peak Load conditions for the corresponding future year.

(2) By October 15th of each year, ERCOT shall update, for each of the next six years, the ERCOT Planning Model and post it to the MIS Secure Area

(3) ERCOT shall make available to TSPs and/or Distribution Service Provider (DSPs) and all appropriate Market Participants, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, the transmission model used in transmission planning. ERCOT shall provide model information through the use of the Electric Power Research Institute (EPRI) and North American Electric Reliability Corporation (NERC) sponsored CIM and web-based Extensible Markup Language (XML) communications or Power System Simulator for Engineering (PSS/E) format.

(4) ERCOT shall post the schedule for updating transmission information on the MIS Secure Area.

(5) ERCOT shall coordinate updates to the Annual Planning Model with the Network Operations Model to ensure consistency of data within and between the Annual Planning Model and Network Operations Model to the extent practicable.

3.10.3 CRR Network Model

(1) ERCOT shall develop models for Congestion Revenue Right (CRR) Auctions that contain, as much as practicable, information consistent with the Network Operations

Model. Names of Transmission Elements in the Network Operations Model and the CRR Network Model must be identical for the same physical equipment.

(2) ERCOT shall verify that the names of Hub Buses and Electrical Buses used to describe the same device in any Hub are identically named in both the Network Operations Model and the CRR Network Model.

(3) Each CRR Network Model must include:

(a) A system-wide diagram including all modeled Transmission Elements (except those within Private Use Networks) and Resource Nodes;

(b) Station one-line diagrams for all Settlement Points (indicating the Settlement Point that the Electrical Bus is a part of) and including all Hub Buses used to calculate Hub prices (if applicable), except those within Private Use Networks;

(c) Generation Resource locations;

(d) Transmission Elements;

(e) Transmission impedances;

(f) Transmission ratings, excluding Relay Loadability Ratings;

(g) Contingency lists;

(h) Data inputs used in the calculation of Dynamic Ratings, and

(i) Other relevant assumptions and inputs used for the CRR Network Model.

(4) ERCOT shall make available to TSPs and/or DSPs and all appropriate Market Participants, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, the CRR Network Model. ERCOT shall provide model information through the use of the EPRI and NERC-sponsored CIM and web based XML communications or PSS/E format.

3.10.3.1 Process for Managing Network Operations Model Updates for Point of Interconnection Bus Changes, Resource Retirements and Deletion of DC Tie Load Zones

(1) Following the permanent change in Point of Interconnection Bus (POIB) of all Resources associated with a Resource Node, ERCOT shall retain the associated Settlement Point in the Network Operations Model at its existing location, an electrically similar location, or until all outstanding CRRs associated with that Settlement Point have expired as determined in accordance with the Other Binding Document, “Procedure for Identifying Resource Nodes.” Following the retirement of all Resources associated with a Resource Node, ERCOT shall move the Resource Node to a proxy Electrical Bus. The proxy

Electrical Bus will be selected by finding the nearest energized Electrical Bus with the least impedance equipment between the existing Resource Node and the proxy Electrical Bus. For purposes of the CRR Auction model for calendar periods that are prior to the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will continue to be available as a sink or source for CRR Auction transaction submittals. For calendar periods that are beyond the expiration date of all CRRs associated with the Settlement Point, the Settlement Point will not be available for transaction submittals in the associated CRR Auctions. The Settlement Point will be removed from the Network Operations Model once all associated CRRs have expired.

(2) When a Direct Current Tie (DC Tie) is to be permanently removed from service, ERCOT will delete the associated DC Tie Load Zone from the Network Operations Model after all outstanding CRRs associated with that DC Tie Load Zone have expired. The DC Tie Load Zone will continue to be available as a sink or source Settlement Point for transaction submittals in CRR Auctions for calendar periods that are prior to the scheduled deletion date of the DC Tie Load Zone; however, the DC Tie Load Zone will no longer be an available Settlement Point for transaction submittals in CRR Auctions for calendar periods that are after the scheduled deletion date of the DC Tie Load Zone.

3.10.4 ERCOT Responsibilities

(1) ERCOT shall design, install, operate, and maintain its systems and establish applicable related processes to meet the State Estimator Standards for Transmission Elements that under typical system conditions potentially affect the calculation of Locational Marginal Prices (LMPs) as described in Section 3.10.7.5, Telemetry Standards, and Section 3.10.9, State Estimator Standards. ERCOT shall post all documents relating to the State Estimator Standards on the MIS Secure Area.

(2) During Real-Time, ERCOT shall calculate LMPs and take remedial actions to ensure that actual flow on a given Transmission Element is less than the Normal Rating and any calculated flow due to a contingency is less than the applicable Emergency Rating and 15-Minute Rating.

(3) ERCOT shall install Network Operations Model test facilities that will accommodate execution of a test Real-Time sequence and preliminary test LMP calculator to demonstrate the correct operation of new Network Operations Models prior to releasing the model to Market Participants for detail testing and verification. The Network Operations Model test facilities support power flow and contingency analyses to test the data set representation of a proposed transmission model update and simulate LMP calculations using typical test data.

(4) ERCOT shall install EMS test and simulation facilities that accommodate execution of the State Estimator and LMP calculator, respectively. These facilities will be used to conduct tests prior to placing a new model into ERCOT's production environment to verify the new model's accuracy. The EMS test facilities allow a potential model to be tested before replacing the current production environment model. The EMS test and

simulation facilities must perform Real-Time security analysis to test a proposed transmission model before replacing the current production environment model. The EMS State Estimator test facilities must have Real-Time ICCP links to test the state estimation function using actual Real-Time conditions. The EMS LMP test facilities must accept data uploads from the production environment providing Qualified Scheduling Entity (QSE) Resource offers, and telemetry via ICCP. If the production data are unavailable, ERCOT may employ a data simulation tool or process to develop test data sets for the LMP test facilities. For TSPs, ERCOT shall acquire model comparison software that will show all differences between subsequent versions of the Network Operations Model and shall make this information available to TSPs only within one week following test completion. For non-TSP Market Participants, ERCOT shall post the differences within one week following test completion between subsequent versions of the Redacted Network Operations Model on the MIS Secure Area. This comparison shall indicate differences in device parameters, missing or new devices, and status changes.

(5) When implementing Transmission Element changes, ERCOT shall correct errors uncovered during testing that are due to submission of inaccurate information. Each TSP and Resource Entity shall provide reasonably accurate information at the time of the original submission.

[NPRR857: Replace paragraph (5) 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:]

(5) When implementing Transmission Element changes, ERCOT shall correct errors uncovered during testing that are due to submission of inaccurate information. Each TSP, DCTO, and Resource Entity shall provide reasonably accurate information at the time of the original submission.

(6) ERCOT may update the model on an interim basis, outside of the timeline described in Section 3.10.1, Time Line for Network Operations Model Changes, for the correction of temporary configuration changes in a system restoration situation, such as after a storm, or correction of impedances and ratings.

(7) Interim updates to the Network Operations Model caused by unintentional inconsistencies of the model with the physical transmission grid may be made. If an interim update is implemented, ERCOT shall report changes to the PUCT Staff and the IMM. ERCOT shall provide Notice via electronic means to all Market Participants and post the Notice on the MIS Secure Area detailing the changed model information and the reason for the interim update within two Business Days following the report to PUCT Staff and the IMM.

(8) A TSP and Resource Entity, with ERCOT's assistance, shall validate its portion of the Network Operations Model according to the timeline provided in Section 3.10.1. ERCOT shall provide TSPs access, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, to an environment of the ERCOT EMS where the Network Operations Model and the results of the Real-Time State Estimator are available for review and analysis within five minutes of the Real-Time solution. This environment is provided as a tool to TSPs to perform power flow studies, contingency analyses and validation of State Estimator results.

[NPRR857: Replace paragraph (8) 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:]

(8) TSPs, DCTOs, and Resource Entities, with ERCOT's assistance, shall validate their portion of the Network Operations Model according to the timeline provided in Section 3.10.1. ERCOT shall provide TSPs access, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, to an environment of the ERCOT EMS where the Network Operations Model and the results of the Real-Time State Estimator are available for review and analysis within five minutes of the Real-Time solution. This environment is provided as a tool to TSPs to perform power flow studies, contingency analyses and validation of State Estimator results.

(9) ERCOT shall make available to TSPs, consistent with the requirements regarding ECEII, the Network Operations Model used to manage the reliability of the transmission system as well as proposed Network Operations Models to be implemented at a future date. ERCOT shall post on the MIS Secure Area the Redacted Network Operations Model, consistent with the requirements regarding release of ECEII, as well as proposed Redacted Network Operations Models to be implemented at a future date. ERCOT shall provide model information through the use of the EPRI and NERC-sponsored CIM and web-based XML communications.

3.10.5 TSP Responsibilities

(1) Each TSP shall design, implement, operate, and maintain its systems to meet the requirements of Section 3.10.7.5, Telemetry Requirements, for measurements facilitating the observability of the Electrical Buses used for Security-Constrained Economic Dispatch (SCED). However, there is no obligation to re-construct or retrofit already existing installations except as shown to be needed in order to comply with Section 3.10.7.5 and Section 3.10.9, State Estimator Requirements.

(2) TSPs shall add telemetry to equipment it owns and directly operates and controls at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5. Nothing in this subsection prohibits a TSP from adding telemetry to equipment it does not own but directly operates and controls. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) Each TSP shall provide to ERCOT planned construction information, including Certificate of Convenience and Necessity (CCN) application milestone dates if applicable, all of which shall be updated according to a schedule established by ERCOT.

(4) Each TSP shall provide to ERCOT project status updates of Transmission Facilities that are part of an Reliability Must-Run (RMR) or Must Run Alternative (MRA) exit strategy corresponding to a specific RMR or MRA Agreement that has not been terminated, which shall be updated by the first Business Day of each month, noting any acceleration or delay in planned completion date.

(5) A QSE must receive approval from a TSP prior to using the TSP's telemetry as part of a Generation Resource's Bulk Electric System protection scheme or for generation control. If a TSP has approved a QSE's use of the TSP's telemetry, the TSP shall inform the QSE of any telemetry changes with reasonable notice prior to the change or where prior notice is not possible as soon as reasonably practicable thereafter, including discontinuation of the TSP's provision of such telemetry, and the timeline for the changes.

[NPRR857: Replace Section 3.10.5 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:]

3.10.5 TSP and DCTO Responsibilities

(1) Each TSP and DCTO shall design, implement, operate, and maintain its systems to meet the requirements of Section 3.10.7.5, Telemetry Requirements, for measurements facilitating the observability of the Electrical Buses used for Security-Constrained Economic Dispatch (SCED). However, there is no obligation to re-construct or retrofit already existing installations except as shown to be needed in order to comply with Section 3.10.7.5 and Section 3.10.9, State Estimator Requirements.

(2) Each TSP and DCTO shall add telemetry to equipment it owns and directly operates and controls at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5. Nothing in this subsection prohibits a TSP from adding telemetry to equipment it does not own but directly operates and controls. ERCOT shall request such additions when a lack of data telemetry has caused, or can be

demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) Each TSP and DCTO shall provide to ERCOT planned construction information, including Certificate of Convenience and Necessity (CCN) application milestone dates if applicable, all of which shall be updated according to a schedule established by ERCOT.

(4) Each TSP shall provide to ERCOT project status updates of Transmission Facilities that are part of an Reliability Must-Run (RMR) or Must Run Alternative (MRA) exit strategy corresponding to a specific RMR or MRA Agreement that has not been terminated, which shall be updated by the first Business Day of each month, noting any acceleration or delay in planned completion date.

(5) A QSE must receive approval from a TSP prior to using the TSP's telemetry as part of a Generation Resource's Bulk Electric System protection scheme or for generation control. If a TSP has approved a QSE's use of the TSP's telemetry, the TSP shall inform the QSE of any telemetry changes with reasonable notice prior to the change or where prior notice is not possible as soon as reasonably practicable thereafter, including discontinuation of the TSP's provision of such telemetry, and the timeline for the changes.

3.10.6 QSE and Resource Entity Responsibilities

(1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation Resource, SOG, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads.

[NPRR995: Replace paragraph (1) above with the following upon system implementation:]

(1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation Resource, SOG, SOESS, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads.

(2) QSEs shall ensure availability of telemetry to generation and transmission equipment its Resource Entity owns at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5, Telemetry Requirements. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) For each Generation Resource and Energy Storage Resource (ESR), Resource Entities shall provide ERCOT the following temperature data:

(a) Cold weather temperature limits:

(i) Minimum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without a Forced Outage or Startup Loading Failure due to cold weather after at least one complete winter Peak Load Season following the Resource's Initial Synchronization date based on the previous five calendar years of historical data; and

(ii) Minimum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum rating due to cold weather after at least one complete winter Peak Load Season following the Resource's Initial Synchronization date based on the previous five calendar years of historical data; and

(iii) At least one of the following:

(A) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum sustainable rating; or

(B) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum sustainable rating determined by an engineering analysis; and

(iv) At least one of the following:

(A) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Outage or Startup Loading Failure; or

(B) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Outage or Startup Loading Failure determined by an engineering analysis.

(b) Hot weather temperature limits:

(i) Maximum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Outage or Startup Loading Failure due to hot weather after at least one complete summer Peak Load Season following the Resource's Initial Synchronization date based on the previous five years of historical data; and

(ii) Maximum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating due to hot weather after at least one complete summer Peak Load Season following the Resource's Initial Synchronization date based on the previous five calendar years of historical data; and

(iii) At least one of the following:

(A) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating; or

(B) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating, determined by an engineering analysis; and

(iv) At least one of the following:

(A) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Outage or Startup Loading Failure; or

(B) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Outage or Startup Loading Failure, determined by an engineering analysis.

(4) Each Resource Entity shall review at least annually the temperatures described in paragraphs (3)(a)(i), (3)(a)(ii), (3)(b)(i), and (3)(b)(ii) above and shall update each Resource's Registration data within 30 days of identifying any change in these temperatures.

(5) Each Resource Entity shall review at least once every seven years the temperatures described in paragraphs (3)(a)(iii), (3)(a)(iv), (3)(b)(iii), and (3)(b)(iv) above and shall update each Resource's Registration data within 30 days of identifying any change in these temperatures.

(6) Resource Entities shall update each Generation Resource's alternate fuel information within 30 days of any changes to the alternate fuel information.

3.10.7 ERCOT System Modeling Requirements

(1) The following subsections contain the fidelity requirements for the ERCOT Network Operations Model.

3.10.7.1 Modeling of Transmission Elements and Parameters

(1) ERCOT, each TSP, and each Resource Entity shall coordinate to define each Transmission Element such that the TSP's control center operational model and ERCOT's Network Operations Model are consistent.

[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 and each TSP, DCTO, and Resource Entity shall coordinate to define each Transmission Element such that the TSP's control center operational model and ERCOT's Network Operations Model are consistent.

(2) Each Transmission Element must have a unique identifier using a consistent naming convention used between ERCOT, Resource Entities, and TSPs. ERCOT shall develop the naming convention with the assistance of the TSP and the approval of the Technical Advisory Committee (TAC). In addition to the Network Operations Model releases described in Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall provide all names and parameters of all Transmission Elements to Market Participants posted on MIS Secure Area by 0600 each day.

[NPRR857: Replace paragraph (2) 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:]

(2) Each Transmission Element must have a unique identifier using a consistent naming convention used between ERCOT, Resource Entities, TSPs, and DCTOs. ERCOT shall develop the naming convention with the assistance of the TSP and the approval of TAC. In addition to the Network Operations Model releases described in Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall provide all names and parameters of all Transmission Elements to Market Participants posted on MIS Secure Area by 0600 each day.

(3) If the responsible TSP submits a NOMCR for non-operational changes, such as name changes for Transmission Elements, ERCOT shall implement the request.

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

(3) If the responsible TSP or DCTO submits a NOMCR for non-operational changes, such as name changes for Transmission Elements, ERCOT shall implement the request.

(4) Resource Entities shall provide the data requested in this Section through the Resource Registration data provided pursuant to Planning Guide Section 6.8.2, Resource Registration Process.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) Each Resource Entity shall provide the data requested in this Section through the Resource Registration data provided pursuant to relevant authorities, including Planning Guide Section 6.8.2, Resource Registration Process.

[NPRR1133: Insert paragraph (5) below upon system implementation of NPRR857:]

(5) Each DC Tie Facility owner shall provide the model data needed to accurately reflect the physical characteristics of the DC Tie Facility in ERCOT's Network Operations Model to its DCTO, and the DCTO shall submit the data to ERCOT. The DC Tie Facility owner is responsible for the accuracy and completeness of the data submitted to ERCOT through its DCTO.

3.10.7.1.1 Transmission Lines

(1) ERCOT shall model each transmission line that operates in excess of 60 kV.

(2) For each of its transmission lines operated as part of the ERCOT Transmission Grid, each TSP and if applicable, Resource Entity, shall provide ERCOT with the following information consistent with the ratings methodology prescribed in the ERCOT Operating Guides:

[NPRR857: Replace paragraph (2) 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:]

(2) For each of its transmission lines operated as part of the ERCOT Transmission Grid, each TSP, DCTO, and if applicable, Resource Entity, shall provide ERCOT with the following information consistent with the ratings methodology prescribed in the ERCOT Operating Guides:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) Transmission Element name;

(d) Line impedance;

(e) Normal Rating, Emergency Rating, 15-Minute Rating, Conductor/Transformer 2-Hour Rating, and Relay Loadability Rating; and

(f) Other data necessary to model Transmission Element(s).

(3) The TSP and Resource Entity may submit special transfer limits and stability limits for secure and reliable grid operations for ERCOT approval. ERCOT has sole decision-making authority and responsibility to determine the limits to be applied in grid operations.

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

(3) The TSP, DCTO, and Resource Entity may submit special transfer limits and stability limits for secure and reliable grid operations for ERCOT approval. ERCOT has sole decision-making authority and responsibility to determine the limits to be applied in grid operations.

(4) The TSP and Resource Entity may implement protective relay and control systems and set values appropriate to de-energize faulted equipment and meet the TSP and Resource Entity obligations for public or employee safety, and when necessary to prevent in-service or premature equipment failure consistent with Good Utility Practice and accepted industry standards. The TSP and Resource Entity shall include those limits as Relay Loadability Ratings when providing ERCOT with ratings or proposed transfer limits.

[NPRR857: Replace paragraph (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(4) The TSP, DCTO, and Resource Entity may implement protective relay and control systems and set values appropriate to de-energize faulted equipment and meet the TSP, DCTO, and Resource Entity obligations for public or employee safety, and when necessary to prevent in-service or premature equipment failure consistent with Good Utility Practice and accepted industry standards. The TSP, DCTO, and Resource Entity shall include those limits as Relay Loadability Ratings when providing ERCOT with ratings or proposed transfer limits.

(5) The Network Operations Model must use rating categories for Transmission Elements as defined in the ERCOT Operating Guides.

3.10.7.1.2 Transmission Buses

(1) ERCOT shall model each Electrical Bus that operates as part of the ERCOT Transmission Grid in excess of 60 kV and that is required to model switching stations or transmission Loads.

(2) Each TSP and if applicable, Resource Entity, shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

[NPRR857: Replace paragraph (2) 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:]

(2) Each TSP, DCTO, and if applicable, Resource Entity, shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) A description of all transmission circuits that may be connected through breakers or switches; and

(f) Other data necessary to model Transmission Element(s).

(3) To accommodate the Outage Scheduler, the TSP and Resource Entity may define a separate name and Transmission Element for any Electrical Bus that can be physically separated by a manual switch or breaker within a substation.

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

(3) To accommodate the Outage Scheduler, the TSP, DCTO, and Resource Entity may define a separate name and Transmission Element for any Electrical Bus that can be physically separated by a manual switch or breaker within a substation.

3.10.7.1.3 Transmission Breakers and Switches

(1) ERCOT's Network Operations Model must include all transmission breakers and switches, the operation of which may cause a change in the flow on transmission lines or Electrical Buses. Breakers and switches may only be connected to defined Electrical Buses.

(2) Each TSP and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

[NPRR857: Replace paragraph (2) 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:]

(2) Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Connectivity;

(f) Normal status;

(g) Synchronism check relay phase angle limits that are applied to operator-initiated, non-automated control actions of TSP-owned transmission breakers; and

[NPRR857: Replace item (g) 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:]

(g) Synchronism check relay phase angle limits that are applied to operator-initiated, non-automated control actions of TSP-owned or DCTO-owned transmission breakers; and

(h) Other data necessary to model Transmission Element(s).

(3) ERCOT shall develop methods to accurately model changes in transmission line loading resulting from Load rollover schemes transferring more than ten MW. This may include modeling distribution circuit breakers, dead line sensing, or other methods that signal when the Load should be transferred from one transmission line to another transmission

line. ERCOT may employ heuristic rule sets for all manual Load transfers and for automated transfers where feasible. ERCOT application software is required to model the effects of automatic or manual schemes in the field transfer Load under line outage conditions. Each TSP and as applicable, Resource Entity, shall define the Load rollover schemes under Section 3.10.7.2, Modeling of Resources and Transmission Loads, and furnish this information to ERCOT. Transmission field (right-of-way) switches must be connected to a named Electrical Bus and be included in the Network Operations Model.

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

(3) ERCOT shall develop methods to accurately model changes in transmission line loading resulting from Load rollover schemes transferring more than ten MW. This may include modeling distribution circuit breakers, dead line sensing, or other methods that signal when the Load should be transferred from one transmission line to another transmission line. ERCOT may employ heuristic rule sets for all manual Load transfers and for automated transfers where feasible. ERCOT application software is required to model the effects of automatic or manual schemes in the field transfer Load under line outage conditions. Each TSP and as applicable, each DCTO and Resource Entity, shall define the Load rollover schemes under Section 3.10.7.2, Modeling of Resources and Transmission Loads, and furnish this information to ERCOT. Transmission field (right-of-way) switches must be connected to a named Electrical Bus and be included in the Network Operations Model.

3.10.7.1.4 Transmission, Main Power Transformers (MPTs) and Generation Resource Step-Up Transformers

(1) ERCOT shall model all transformers with a nominal low side (i.e., secondary, not tertiary) voltage above 60 kV.

(2) For Generation Resources, ERCOT shall model all Main Power Transformers (MPTs) and Generator Step-Up (GSU) transformers greater than ten MVA to provide for accurate representation of generator voltage control capability including the capability to accept a system operator entry of a specific no-load tap position, or if changeable under Load, accept telemetry of the current tap position.

(3) Each TSP and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP and Resource Entity shall provide ERCOT with the

following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

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

(3) Each TSP, DCTO, and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Winding ratings, including Normal Rating, Emergency Rating, 15-Minute Rating, Conductor/Transformer 2-Hour Rating, and Relay Loadability Rating;

(f) Connectivity;

(g) Transformer parameters, including all tap parameters; and

(h) Other data necessary to model Transmission Element(s).

(4) The Resource Entity shall provide parameters for each MPT to ERCOT as part of the Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process. ERCOT shall provide the information to TSPs. Each TSP shall coordinate with the operators of the Resources connected to their respective systems to establish the proper transformer tap positions (no-load taps) and the equipment owner shall report any changes to ERCOT using the NOMCR process or other ERCOT prescribed means. Each Resource Entity and each TSP shall schedule generation Outages at mutually agreeable times to implement tap position changes when necessary. If mutual agreement cannot be reached, then ERCOT shall decide where to set the tap position to be implemented by the Resource Entity at the next generation Outage, considering expected impact on system security, future Outage plans, and participants. TSPs shall provide ERCOT and Market Participants with notice in accordance with

paragraph (4) of Section 3.10.4, ERCOT Responsibilities, (except for emergency) prior to the tap position change implementation date.

(5) ERCOT shall post to the MIS Secure Area information regarding all transformers represented in the Network Operations Model.

3.10.7.1.5 Reactors, Capacitors, and other Reactive Controlled Sources

(1) ERCOT shall model all controlled reactive devices. Each Market Participant shall provide ERCOT with complete information on each device's capabilities and normal switching schema.

(2) Each Market Participant shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Voltage or time switched on;

(f) Voltage or time switched off;

(g) Associated switching device name;

(h) Connectivity;

(i) Nominal voltage and associated capacitance or reactance; and

(j) Other data necessary to model Transmission Element(s).

(3) The ERCOT Operating Guides must include parameters for standard reactor and capacitor switching plans for use in the Network Operations Model. ERCOT shall model the devices under Section 3.10.4, ERCOT Responsibilities, in all applicable ERCOT applications and systems. ERCOT shall provide copies of the switching plan to the Market Participants via the MIS Secure Area. Any change in TSP guidelines or switching plan must be provided to ERCOT before implementation (except for emergency). Any change in guidelines or switching plan must be provided in accordance with the NOMCR process or other ERCOT-prescribed process.

3.10.7.2 Modeling of Resources and Transmission Loads

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), and the non-TSP owned MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

[NPRR995: Replace paragraph (1) above with the following upon system implementation:]

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, SOESSs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), and the non-TSP MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

(2) Each Resource Entity representing either a Load Resource or an Aggregate Load Resource (ALR) shall provide ERCOT and, as applicable, its interconnecting DSP and TSP, with information describing each such Resource as specified in Section 3.7.1.2, Load Resource Parameters, and any additional information and telemetry as required by ERCOT, in accordance with the timelines set forth in Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall coordinate the modeling of ALRs with Resource Entities. ERCOT shall coordinate with representatives of the Resource Entity to map Load Resources to their appropriate Load in the Network Operations Model.

(3) Each Resource Entity representing a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) that is registered with ERCOT pursuant to Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its DGR or DESR facilities, and additional information and telemetry as required by ERCOT and the interconnecting DSP. ERCOT shall coordinate with representatives of the Resource Entity to represent the registered DGR or DESR facilities at their appropriate Electrical Bus in the Network Operations Model.

(4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall

provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG facilities to their appropriate Load in the Network Operations Model.

[NPRR995: Replace paragraph (4) above with the following upon system implementation:]

(4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) or Settlement Only Distribution Energy Storage System (SODESS) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG or SODESS facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG or SODESS facilities to their appropriate Load in the Network Operations Model.

(5) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility MPT.

(6) ERCOT shall create a DC Tie Resource to represent an equivalent generation injection to represent the flow into the ERCOT Transmission Grid from operation of DC Ties. The actual injection flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Resource output.

(7) TSPs shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

[NPRR857: Replace paragraph (7) 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:]

(7) Each TSP and DCTO shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

(8) ERCOT may require TSPs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP shall notify ERCOT if the owner does not comply with the request.

[NPRR857: Replace paragraph (8) 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:]

(8) ERCOT may require TSPs and DCTOs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP or DCTO does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP or DCTO shall notify ERCOT if the owner does not comply with the request.

(9) ERCOT shall create a DC Tie Load to represent an equivalent Load withdrawal to represent the flow from the ERCOT Transmission Grid from operation of DC Ties. The actual withdrawal flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Load output.

(10) Each TSP shall also provide information to ERCOT describing automatic Load transfer (rollover) plans and the events that trigger which Loads are switched to other Transmission Elements on detection of Outage of a primary Transmission Element. ERCOT shall accommodate Load rollover plans in the Network Operations Model.

(11) Loads associated with a Generation Resource in a common switchyard as defined in Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and served

through a transformer owned by the Resource Entity is treated as an auxiliary Load and must be netted first against any generation meeting the requirements under Section 10.3.2.3.

(12) If the Day-Ahead Market (DAM) determines, in the processing of Outages, that a Load Resource, DGR, or DESR is de-energized in the ERCOT Network Operations Model, the de-energized Resource will be eligible to receive Ancillary Service awards in the DAM, but will not be eligible to receive energy awards in the DAM.

(13) A Resource Entity may aggregate Intermittent Renewable Resource (IRR) generation equipment together to form an IRR (Wind-powered Generation Resource (WGR) or PhotoVoltaic Generation Resource (PVGR)) if the generation equipment is behind the same main power transformer and is the same model and size, and the aggregation does not reduce ERCOT's ability to model pre- and post-contingency conditions. A Resource Entity may also aggregate IRR generation equipment that is not the same model and size together with an existing IRR only if:

(a) The mix of IRR generation equipment models and sizes causes no degradation in the dynamic performance of the IRR represented by the parameters modeled by ERCOT in operational studies and the aggregation of IRR generation equipment does not limit ERCOT's ability to model the ERCOT Transmission Grid and the relevant contingencies required for monitoring pre- and post-contingency system limits and conditions;

(b) The mix of IRR generation equipment is included in the Resource Registration data submitted for the WGR;

(c) All relevant IRR generation equipment data requested by ERCOT is provided;

(d) With the addition of dissimilar IRR generation equipment, the existing IRR shall continue to meet the applicable Protocol performance requirements, including but not limited to Primary Frequency Response, dynamic capability and Reactive Power capability, at the POIB; and

(e) Either:

(i) No more than the lower of 5% or ten MW aggregate capacity is of IRR generation equipment that is not the same model or size from the other equipment within the existing IRR; or

(ii) The wind turbines that are not the same model or size meet the following criteria:

(A) The IRR generation equipment has similar dynamic characteristics to the existing IRR generation equipment, as determined by ERCOT in its sole discretion;

(B) The MW capability difference of each generator is no more than 10% of each generator's maximum MW rating; and

(C) For WGRs, the manufacturer's power curves for the wind turbines have a correlation of 0.95 or greater with the other wind turbines within the existing WGR over wind speeds of 0 to 18 m/s.

3.10.7.2.1 Reporting of Demand Response

(1) ERCOT shall post on the ERCOT website by the fifth Business Day after the start of a calendar month a report of the MW of Demand response that is participating in the past month in Emergency Response Service (ERS), Ancillary Service as a Load Resource, or any pilot project permitted by subsection (k) of P.U.C. SUBST. R. 25.361, Electric Reliability Council of Texas (ERCOT). The data shall be aggregated according to the corresponding 2003 ERCOT Congestion Management Zone (CMZ). Data for participation in ERS shall be based on contracted amounts for each type of service for that calendar month. ERCOT shall set out separately MW contracted from both ERS Generators and generators that are participating by offsetting ERS Loads (with aggregated and non-aggregated ERS Generators set forth separately) and MW of ERS Loads. To the extent that a participating generator is not registered with ERCOT, information about the nameplate rating of the generator and the maximum deliverable to the ERCOT Transmission Grid or to serve native load shall be collected through the ERS contracting process. The report shall include these values for each ERS Contract Period broken down by ERS Time Period. Data for Ancillary Services shall be based on the Ancillary Service Resource Responsibility contained in the Current Operating Plan (COP) as of the start of the Adjustment Period for each Operating Day. ERCOT's posting of Ancillary Service and pilot project participation data shall include the average MW capacity by service type by hour (or by another time period, if a pilot project service is not procured hourly).

[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) ERCOT shall post on the ERCOT website by the fifth Business Day after the start of a calendar month a report of the MW of Demand response that is participating in the past month in Emergency Response Service (ERS), Ancillary Service as a Load Resource, or any pilot project permitted by subsection (k) of P.U.C. SUBST. R. 25.361, Electric Reliability Council of Texas (ERCOT). The data shall be aggregated according to the corresponding 2003 ERCOT Congestion Management Zone (CMZ). Data for participation in ERS shall be based on contracted amounts for each type of service for that calendar month. ERCOT shall set out separately MW contracted from both ERS Generators and generators that are participating by offsetting ERS Loads (with aggregated and non-aggregated ERS Generators set forth separately) and MW of ERS Loads. To the extent that a participating generator is not registered with ERCOT, information about the nameplate rating of the generator and the maximum deliverable to the ERCOT Transmission Grid or to serve native load shall be collected through the

ERS contracting process. The report shall include these values for each ERS Contract Period broken down by ERS Time Period. Data for Ancillary Services shall be based on the Ancillary Service Resource awards in the RTM. ERCOT's posting of Ancillary Service and pilot project participation data shall include the average MW capacity by service type by hour (or by another time period, if a pilot project service is not procured hourly).

3.10.7.2.2 Annual Demand Response Report

(1) On an annual basis, ERCOT shall work with Market Participants to produce a report summarizing aggregate customer counts and MWs enrolled in Demand response in the ERCOT Region pursuant to subsection (e)(5) of P.U.C. SUBST. R. 25.505, Reporting Requirements and the Scarcity Pricing Mechanism in the Electric Reliability Council of Texas Power Region. This report shall be posted to the ERCOT website no later than December 31 of each reporting calendar year. Technical requirements for providing information to ERCOT for the report are located in the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications". ERCOT may, for purposes of this section, associate Entities; however, ERCOT shall not determine Non-Opt-In Entities (NOIEs) to be associated based on their membership in a generation and transmission cooperative or as a result of being a party to a single Load Serving Entity (LSE) registration.

(a) Retail Electric Providers (REPs) in competitive regions of ERCOT shall be ranked in descending order by their average daily consumption for summer (June – September) weekdays excluding holidays. The largest REPs that account for 98% of the total shall be required to participate in the survey for the subsequent calendar year. For purposes of assigning this participation requirement, REPs determined by ERCOT to be associated shall have their consumption aggregated prior to the ranking.

(b) NOIE Transmission and/or Distribution Service Providers (TDSPs) operating in the ERCOT Region that register a summer month (June – September) 15-minute interval peak Demand greater than or equal to 100 MW, shall be required to participate in the survey the subsequent calendar year. For purposes of assigning this participation requirement, NOIEs determined by ERCOT to be associated shall have their 15-minute interval peak Demand aggregated prior to the ranking. Participation in the survey shall be the responsibility of either the NOIE TDSP or the NOIE LSE associated with that TDSP based on which entity is responsible for administering Demand response programs within the NOIE TDSP footprint.

(2) By December 31 of each year, ERCOT shall provide advance notice of participation status. To the extent that REPs discontinue participation in the ERCOT market or change associations prior to the snapshot date, ERCOT will send revised notices to REPs affected by such changes no later than August 1 of the survey year. ERCOT shall:

(a) Analyze the summer consumption for all NOIEs and REPs and determine which are required to participate in the Demand response survey for the following year;

(b) Provide advance notice, via email to the Authorized Representative, to all NOIEs and REPs regarding their participation status; and

(c) Provide a list of all REPs or NOIE TDSPs to the Authorized Representative, including all those determined by ERCOT to be associated, to which the participation status applies.

(3) By August 1 of the survey year, ERCOT shall provide official notice of the beginning of the Demand response data collection process. ERCOT shall:

(a) Issue a Market Notice to notify all REPs and NOIEs that the annual Demand response data collection process is beginning. The Market Notice shall make reference to this Protocol section, and shall reiterate specifics of the timeline for the survey process that are to be followed;

(b) Send a reminder email to the Authorized Representative for all REPs, NOIE LSEs and NOIE TDSPs of their participation status. The email shall also contain the list of all REPs or NOIE TDSPs, for which participation status applies. The list shall include all REPs or NOIE TDSPs determined by ERCOT to be associated. This list shall be updated based on any changes in associations that have occurred since the time the advance notice was issued.

(4) By August 15 of the survey year, REPs and NOIEs that are required to participate in that year's survey, and that will have Customers participating in one or more Demand response program as of the snapshot date of September 1 shall reply to ERCOT with the following:

(a) An acknowledgement of the participation requirement;

(b) An indication that they expect to have Customers participating in one or more Demand response programs on the snapshot date of September 1;

(c) A list of contact people and their email address within their organization that should receive copies of communications related to the survey from ERCOT;

(d) Specifically for REPs, an indication as to which of the methods described in the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications" the REP intends to use to submit files to and receive files from ERCOT; and

(e) Specifically for NOIEs, an indication as to whether the NOIE TDSP or the NOIE LSE is responsible for administering the Demand response programs within the NOIE TDSP area.

(5) By August 15 of the survey year, REPs and NOIEs that are required to participate in that year's survey, and that do not plan to have any Customers participating in Demand response programs as of the snapshot date of September 1 shall reply to ERCOT indicating the lack of such participation. REPs and NOIEs that are not required to participate in that year's survey are not required to reply to ERCOT.

(6) By October 15 of the survey year, the REPs participating in that year's survey shall compile the required Electric Service Identifier (ESI ID) participation data in the format specified by the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications", and submit the data to ERCOT.

(7) By October 31 of the survey year, the REPs participating in that year's survey that have reported participation in programs which entail REP-initiated deployments shall compile the required deployment event participation data in the format specified by the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications", and submit the data to ERCOT.

(8) By October 31 of the survey year, the NOIEs participating in that year's survey shall compile the required data in the format specified by the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications", and submit the data to ERCOT.

(9) ERCOT shall validate the submitted reports, and indicate any errors and inconsistencies that require correction to the REP or NOIE, within two Business Days of the submission in the manner specified in the Other Binding Document titled "Demand Response Data Definitions and Technical Specifications".

(10) On or before October 31 of the survey year, REPs shall address the errors and inconsistencies and submit corrected reports to ERCOT. ERCOT will notify the Authorized Representative for each REP and/or NOIE when they have achieved the required level of accuracy.

(11) On or before November 7 of the survey year, NOIEs shall address the errors and inconsistencies and submit corrected reports to ERCOT. ERCOT will notify the Authorized Representative for each REP and/or NOIE when they have achieved the required level of accuracy.

(12) Information provided by NOIEs and REPs to meet the above described reporting requirements shall be treated as Protected Information in accordance with Section 1.3, Confidentiality.

3.10.7.3 Modeling of Private Use Networks

(1) ERCOT shall create and use network models describing Private Use Networks according to the following:

(a) A Generation Entity with a Resource located within a Private Use Network shall provide data to ERCOT, for use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network in accordance with Section 3.3.2.1, Information to Be Provided to ERCOT, if it meets any one of the following criteria:

(i) Contains a generator greater than ten MW and is registered with the PUCT according to P.U.C. SUBST. R. 25.109, Registration of Power Generation Companies and Self-Generators, as a power generation company; or

(ii) Is part of a Private Use Network which contains more than one connection to the ERCOT Transmission Grid; or

(iii) Contains generation registered to provide Ancillary Services.

(b) A Generation Entity with an SOTSG shall provide to ERCOT annually, or more often upon change, the following information for ERCOT's use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network:

(i) Equipment owner(s);

(ii) Equipment operator(s);

(iii) TSP substation name connecting the Private Use Network to the ERCOT System;

(iv) At the request of ERCOT, a description of Transmission Elements within the Private Use Network that may be connected through breakers or switches;

(v) Net energy delivery metering, as required by ERCOT, to and from the Private Use Network and the ERCOT System at the POIB;

(vi) For each individual generator located within the Private Use Network, the gross capacity in MW and its reactive capability curve;

(vii) Maximum and minimum reasonability limits of the Load located within the Private Use Network;

(viii) Outage schedule for each generation unit located within the Private Use Network, updated as changes occur from the annually submitted information; and

(ix) Other interconnection data as required by ERCOT.

(c) Energy delivered to ERCOT from an SOTSG shall be settled in accordance with Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone.

(d) ERCOT shall ensure the Network Operations Model properly models the physical effect of the loss of generators and Transmission Elements on the ERCOT Transmission Grid equipment loading, voltage, and stability.

(e) ERCOT may require the owner or operator of a Private Use Network to provide information to ERCOT and the TSP on Transmission Facilities located within the Private Use Network for use in the Network Operations Model if the information is required to adequately model and determine the security of the ERCOT Transmission Grid, including data to perform loop flow analysis of Private Use Networks.

(f) ERCOT shall review submittals of modeling data from owners or operators of Private Use Networks assure that it will result in correct analysis of ERCOT Transmission Grid security.

3.10.7.4 Remedial Action Schemes, Automatic Mitigation Plans and Remedial Action Plans

(1) All approved Remedial Action Schemes (RASs), Automatic Mitigation Plans (AMPs) and Remedial Action Plans (RAPs) must be defined in the Network Operations Model where practicable.

(2) Proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs and Resource Entities that own Transmission Facilities included in the RASs or AMPs or RAPs, and shall approve proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

[NPRR857: Replace paragraph (2) 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:]

(2) Proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs, DCTOs, and Resource Entities that own Transmission Facilities included in the RASs or AMPs or RAPs, and shall approve proposed new RASs, AMPs and RAPs and proposed changes to RASs, AMPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs,

AMPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

(3) ERCOT shall use a NOMCR to model approved RASs, AMPs and RAPs where practicable and include the RASs, AMPs or RAPs modeled in the Network Operations Model in the security analysis. The NOMCR shall include a detailed description of the system conditions required to implement the RASs, AMPs or RAPs. If an approved RAS, AMP, or RAP cannot be modeled, then ERCOT shall develop an alternative method for recognizing the unmodeled RAS, AMP, or RAP in its tools. Execution of RASs, AMPs or RAPs modeled in the Network Operations Model shall be included or assumed in the calculation of LMPs. ERCOT shall provide notification to the market and post on the MIS Secure Area all approved RASs, AMPs and RAPs at least two Business Days before implementation, identifying the date of implementation. The notification to the market shall state whether the approved RAP, AMP, or RAS will be modeled in the Network Operations Model. For RAPs developed in Real-Time, ERCOT shall provide notification to the market as soon as practicable.

3.10.7.5 Telemetry Requirements

(1) The telemetry provided to ERCOT necessary to support the State Estimator must meet the requirements set forth in Section 3.10.9, State Estimator Requirements.

(2) The telemetry provided to ERCOT by each TSP and QSE must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP and QSE. ERCOT shall represent data condition codes from each TSP and QSE in a consistent manner for all applicable ERCOT applications.

[NPRR857: Replace paragraph (2) 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:]

(2) The telemetry provided to ERCOT by each TSP, QSE, or DCTO must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP, DCTO, and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data

has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP, DCTO, and QSE. ERCOT shall represent data condition codes from each TSP, DCTO, and QSE in a consistent manner for all applicable ERCOT applications.

(3) Each TSP and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

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

(3) Each TSP, DCTO, and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, DCTO's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

(4) When ERCOT identifies a reliability concern, a deficiency in system observability, or a deficiency in measurement to support the representation of Model Loads, and that concern or deficiency is not due to any inadequacy of the State Estimator program, additional telemetry may be requested as described in Section 3.10.7.5.9, ERCOT Requests for Telemetry.

3.10.7.5.1 Continuous Telemetry of the Status of Breakers and Switches

(1) Each TSP and QSE shall be responsible for providing telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource owns, respectively, used to switch any Transmission Element or Load modeled by ERCOT.

(2) Each TSP and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP or Resource Entity switching operations and TSP or Resource Entity personnel.

(3) Each TSP, Resource Entity, or QSE shall update the status of any breaker or switch it owns or is responsible for through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

(4) If in the sole opinion of ERCOT, the manual updates of the TSP or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP or QSE, and then to ERCOT.

(a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Model Loads in LMP results versus the cost to remedy.

(b) If the TSP or QSE disputes the request for additional telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry.

[NPRR857: Replace paragraphs (1) through (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each TSP, DCTO, and QSE shall provide telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource Entity owns, respectively used to switch any Transmission Element or Load modeled by ERCOT.

(2) Each TSP, DCTO, and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered

status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP, DCTO, or QSE switching operations and TSP, DCTO, or QSE personnel.

(3) Each TSP, DCTO, and QSE shall update the status of any breaker or switch it owns or its Resource Entity owns, respectively, through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

(4) If in the sole opinion of ERCOT, the manual updates of the TSP, DCTO, or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP, DCTO, or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP, DCTO, or QSE, and then to ERCOT.

(a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Model Loads in LMP results versus the cost to remedy.

(b) If the TSP or associated QSE disputes the request for additional telemetry it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry.

(5) ERCOT shall measure TSP and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

[NPRR857: Replace paragraph (5) 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:]

(5) ERCOT shall measure TSP, DCTO, and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

(6) Unless there is an Emergency Condition, TSPs and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in

response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

[NPRR857: Replace paragraph (6) 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:]

(6) Unless there is an Emergency Condition, TSPs, DCTOs, and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs, DCTOs, and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

(7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the device for security analysis as updated by the Outage Scheduler and through verbal communication with the TSP or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

[NPRR857: Replace paragraph (7) 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:]

(7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the device for security analysis as updated by the Outage Scheduler and through verbal communication with the TSP, DCTO, or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

(8) ERCOT shall establish a system that provides alarms to ERCOT Operators when there is a change in status of any monitored transmission breaker or switch, and an indication of whether the device change of status was planned in the Outage Scheduler. ERCOT Operators shall monitor any changes in status not only for reliability of operations, but also for accuracy and impact on the operation of the SCED functions and subsequent potential for calculation of inaccurate LMPs.

(9) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources, Energy Storage Resources, Distribution Generation Resources, and Distribution Energy Storage Resources, shall provide ERCOT with telemetry of the actual generator breakers and switches continuously providing ERCOT with the status of the individual Split Generation Resource.

3.10.7.5.2 Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows

(1) Each TSP and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section 3.10.9, State Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

[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) Each TSP, DCTO, and QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element it owns or its Resource Entity owns, respectively, to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to meet the State Estimator requirements set forth in Section 3.10.9, State Estimator Requirements, with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

(2) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, Combined Cycle Generation Resources, Quick Start Generation Resources, Hydro Generation Resources,

Energy Storage Resources, and Distribution Generation Resources, and Distribution Energy Storage Resources, shall provide ERCOT with telemetry of the actual equivalent generator injection of its Split Generation Resource and the Master QSE shall provide telemetry in accordance with Section 6.5.5.2, Operational Data Requirements, on a total Generation Resource basis. ERCOT shall calculate the sum of each QSE's telemetry on a Split Generation Resource and compare the sum to the telemetry for the total Generation Resource. ERCOT shall notify each QSE representing a Split Generation Resource of any errors in telemetry detected by the State Estimator.

(3) Each TSP and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry.

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

(3) Each TSP, DCTO, and QSE shall provide telemetered measurements at a periodicity of ten seconds on modeled Transmission Elements it owns or its Resource Entity owns, respectively, to ensure State Estimator observability of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed to meet the State Estimator requirements set forth in Section 3.10.9. On monitored non-Load substations, ERCOT may request additional telemetry in accordance with Section 3.10.7.5.10, ERCOT Requests for Redundant Telemetry.

(4) The accuracy of the State Estimator is critical to successful market operations. For this reason it is a critical objective for ERCOT to maintain reasonable and accurate results of the State Estimator. ERCOT shall use all reasonable efforts to achieve that objective, including the provision of legitimate constraints used in calculating LMPs.

(5) Each TSP, QSE and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:

(a) 5% of the largest line Normal Rating at the State Estimator Bus; or

(b) Five MW, whichever is greater.

If a location chronically fails this test, ERCOT shall notify the applicable TSP or QSE and suggest actions that the TSP or QSE could take to correct the failure. Within 30 days, the TSP or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis.

[NPRR857: Replace paragraph (5) 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:]

(5) Each TSP, DCTO, QSE, and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate State Estimator results as outlined in Section 3.10.9. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT System operators if the residual sum of all telemetered measurements is more than:

(a) 5% of the largest line Normal Rating at the State Estimator Bus; or

(b) Five MW, whichever is greater.

If a location chronically fails this test, ERCOT shall notify the applicable TSP, DCTO, or QSE and suggest actions that the TSP, DCTO, or QSE could take to correct the failure. Within 30 days, the TSP, DCTO, or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected time frame to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any State Estimator Buses not meeting the State Estimator requirements set forth in Section 3.10.9, including a list of all measurements and the residual errors on a monthly basis.

(6) ERCOT shall implement a study mode version of the State Estimator with special tools designed for troubleshooting and tuning purposes that can be used independently of any other ERCOT process that is dependent on the Real-Time State Estimator. ERCOT shall implement a process to recognize inaccurate State Estimator results and shall create and implement alternative Real-Time LMP calculation processes for use when inaccurate results are detected. ERCOT must be guided in this by Section 3.10.9.

(7) ERCOT shall establish a system to provide overload and over/under limit alarming on all Transmission Elements monitored as constraints in the LMP models.

(8) Each TSP shall designate which telemetered measurement of the POIB voltage shall be utilized to determine compliance with Voltage Set Point instructions, and then update the designation as necessary in the Network Operations Model by submitting a NOMCR. Each TSP shall telemeter this POI kV bus measurement to ERCOT. If the TSP cannot provide a kV bus measurement at the POI, the TSP may propose an alternate location subject to ERCOT approval.

[NPRR1098: Insert paragraph (9) below upon system implementation and satisfying the following conditions: (1) Southern Cross Transmission LLC (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 Transmission Service Provider (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:]

(9) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support, shall designate which telemetered measurement of the POIB voltage shall be utilized to determine compliance with target voltage instructions, and then update the designation as necessary in the Network Operations Model by submitting a NOMCR. Each TO shall telemeter this POI kV bus measurement to ERCOT via ICCP and the DCTO via telemetry. If the TO cannot provide a kV bus measurement at the POI, the TO may propose an alternate location subject to ERCOT approval.

3.10.7.5.3 Required Telemetry of Voltage and Power Flow

(1) QSEs, Resource Entities and TSPs as indicated in each subsection below shall provide power operation data to ERCOT, including, but not limited to:

(a) Real-Time generation data from QSEs;

(b) Planned and Forced Outage information from QSEs;

(c) Network data from TSPs and QSEs , including:

(i) Breaker and line switch status of all ERCOT Transmission Grid devices;

(ii) Line flow MW and MVAr;

(iii) Breaker and switch status connected to any Resource;

(iv) Transmission Facility voltages; and

(v) Transformer MW, MVAr and tap;

(d) Real-Time generation and Load Resource meter data from QSEs;

(e) Real-Time generation meter splitting signal from QSEs;

(f) Transmission Facility Planned and Forced Outage information from TSPs;

(g) Network transmission data (model and constraints) from TSPs; and

(h) Resource modeling data, including any Resource owned transmission equipment data from Resource entity; and

(i) Dynamic schedules from QSEs.

(2) Real-Time data will be provided to ERCOT at the same scan rate as the TSP, Resource Entity, or QSE obtains the data from telemetry unless ERCOT requests a slower rate.

3.10.7.5.4 General Telemetry Performance Criteria

(1) The following criteria will apply to telemetry provided to ERCOT. Performance is posted on the MIS Secure Area in accordance with Nodal Operating Guide Section 9, Monitoring Programs:

(a) Each TSP shall maintain the sum of flows into any telemetered bus it owns or is responsible for less than the greater of five MW or 5% of the largest normal line rating at each bus.

(b) Each TSP and QSE shall provide data to ERCOT that meets the following availability:

(i) 92% of all telemetry provided to ERCOT must achieve a quarterly availability of 80%. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of Real-Time data with a Valid, Manual, or Calculated quality code at the scheduled periodicity. Quality codes are defined in Section 3.10.7.5.8.1, Data Quality Codes.

(ii) TSPs shall make reasonable efforts to obtain data from Customers associated with new Customer-owned substations to meet this requirement or obtain agreement from ERCOT that these Customers have entered into arrangements with ERCOT to provide this data to ERCOT. If the data cannot be obtained under either of these methods, ERCOT shall report such case to the IMM.

(c) Exceptions to the general telemetry performance criteria may be made, at ERCOT's sole discretion, for data points not significant in the solution of the State Estimator or required for the reliable operation on the ERCOT Transmission Grid. Examples of such data points include but are not limited to:

(i) A substation with no more than two transmission lines and less than ten MW of peak Load;

(ii) Connection of Loads along a continuous, non-branching circuit that may be combined for telemetry purposes; and

(iii) Substations connected radially to the ERCOT Transmission Grid.

(d) During a Force Majeure Event, ERCOT may suspend requirements until normal operations have resumed.

3.10.7.5.5 Supplemental Telemetry Performance Criteria

(1) ERCOT shall identify specific MW/MVAr telemetry pairs, not exceeding 10% of the Transmission Elements within the ERCOT System, and the 20 station voltage points that are most important to reliability, system observability or support of State Estimator performance, or are of a commercial market concern.

(2) The important telemetry points identified pursuant to this Section must meet more stringent criteria for accuracy and availability where specifically addressed. ERCOT shall review this list annually. ERCOT shall publish the list of important telemetry points quarterly on the MIS Secure Area.

(3) ERCOT shall use the following criteria to identify the important telemetry points:

(a) Loss of a telemetry point that results in the inability of ERCOT to monitor loading on a transmission line operated at 345 kV or above.

(b) Loss of a telemetry point that results in the inability of ERCOT to monitor loading on a 345/138 kV autotransformer.

(c) Loss of a telemetry point that results in the inability of ERCOT to monitor the loading on Transmission Facilities designated as important to transmission reliability by ERCOT.

(d) Telemetry necessary to monitor Transmission Elements identified as causing 80% of all congestion cost in the year for which the most recent data is available.

(e) Telemetry necessary to monitor the bus voltages at the 20 most important station voltage points.

(4) Each TSP and QSE shall provide data to ERCOT such that 92% of the important telemetry points identified achieve a quarterly availability of 90%. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of Real-Time data with Valid, Manual, or Calculated quality codes at the scheduled periodicity. Quality codes are defined in Section 3.10.7.5.8.1, Data Quality Codes.

3.10.7.5.6 TSP/QSE Telemetry Restoration

(1) Telemetered data shall be provided continuously. Real-Time data restoration shall comply with Nodal Operating Guide Sections 7.3.3, Data from WAN Participants to ERCOT, and 7.3.4, Resolving Real-Time Data Issues that affect ERCOT Network Security Analysis.

(2) Some data may be more essential to the State Estimator solution. ERCOT shall inform the TSP or QSE if, in the sole opinion of ERCOT, a data item is essential and needs to be repaired as quickly as possible. QSEs and TSPs shall make repair procedures and records available to ERCOT upon request. When ERCOT notifies a data provider that a data element is providing telemetry data inconsistent with surrounding measurements, the provider shall, within 30 days, do one of the following:

(a) Calibrate or repair the failing equipment;

(b) Request an outage to schedule calibration or repair of the failing equipment;

(c) Provide ERCOT with a plan to re-calibrate or repair the equipment in a reasonable time frame; or

(d) Provide ERCOT with engineering analysis proving the data element is providing accuracy within its specifications.

(3) Before ERCOT requests review or re-calibration of a problem piece of equipment, it shall discuss the problem with the data provider to attempt to arrive at a consensus decision on the most appropriate action.

3.10.7.5.7 Calibration, Quality Checking, and Testing

(1) It is the responsibility of the equipment owner to insure that calibration, testing, and other routine maintenance of equipment is done on a timely basis, and that accuracy meets or exceeds the requirements specified in this Section 3.10.7.5, Telemetry Requirements, for both the overall system and for individual equipment where detailed herein. Coordination with ERCOT of outages required for these activities is also the responsibility of the owner.

3.10.7.5.8 Inter-Control Center Communications Protocol (ICCP) Links

3.10.7.5.8.1 Data Quality Codes

(1) Market Participants shall provide documentation to ERCOT describing their native system quality codes and defining the conversion of their quality codes into the ERCOT-defined quality codes.

(2) Statuses and analogs telemetered to ERCOT shall be identified with the following quality codes:

(a) Valid – Represents an analog or status the TSP or QSE considers valid.

(b) Manual – Represents an analog or status entered manually at the Market Participant (i.e., not received from the field electronically).

(c) Calculated – Represents an analog point that the TSP or QSE calculates.

(d) Suspect – Represents an analog or status of which the TSP or QSE is unsure of the validity

(e) Invalid – Represents an analog or status that the Market Participant has identified as out of reasonability limits.

(f) Com_fail – Informs ERCOT that due to communications failure, the analog or status provided ERCOT is not current.

3.10.7.5.8.2 Reliability of ICCP Associations

(1) Each Market Participant using ICCP associations must achieve a monthly availability of 98%, excluding approved Planned Outages. Availability shall be measured based on end-to-end connectivity of the communications path and the passing of configured data at the scheduled periodicity. To meet the 98% monthly availability, each Market Participant should establish a process to coordinate downtime for ICCP associations and database maintenance. High availability configuration as allowed by the ERCOT Nodal ICCP Communication Handbook should be treated as a single association to achieve this availability measure.

3.10.7.5.9 ERCOT Requests for Telemetry

(1) ERCOT is required to protect Transmission Facilities operated at 60 kV or above from damage. To do this, ERCOT may request that additional telemetry be installed, while attempting to minimize adding equipment to as few locations as practicable.

(2) ERCOT may request additional telemetry when it determines that network observability or the measurement redundancy is not adequate to produce acceptable State Estimator results.

(3) Prior to making a request for additional telemetry, ERCOT shall provide evidence supporting a congestion or reliability problem requiring additional observability and define expected improvements in ERCOT System observability needed. If the request is for telemetry additions at more than one location, ERCOT shall prioritize the requested additions.