COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF	**)**	
BIG RIVERS ELECTRIC CORPORATION	**)**	**CASE NO. 2019-00269**
FOR ENFORCEMENT OF	**)**	
RATE AND SERVICE STANDARDS	**)**	

CITY OF HENDERSON, KENTUCKY, AND HENDERSON UTILITY COMMISSION d/b/a HENDERSON MUNICIPAL POWER & LIGHT'S RESPONSES TO BIG RIVERS ELECTRIC CORP.'S INITIAL REQUEST FOR INFORMATION

BEFORE THE PUBLIC SERVICE COMMISSION
IN THE MATTER OF
APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-269

VERIFICATION

I, Brad Bickett, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

Brad Bickett
Brad Bickett

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN to before me by Brad Bickett on this the 11th day of August, 2020.

TAMMY KONSLER NOTARY PUBLIC ID NO. 579781 MY COMMISSION EXPIRES 5/28/2021 STATE AT LARGE, KY.

Tammy Konsler
Notary Public, Kentucky State at Large
My Commission Expires: 5-28-2021
Notary ID #: 579781

BEFORE THE PUBLIC SERVICE COMMISSION
IN THE MATTER OF
BIG RIVERS ELECTRIC CORPORATION
APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR
ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-269

VERIFICATION

I, Seth W. Brown, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

Seth W. Brown

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN to before me by Seth W. Brown on this the 10th day of August, 2020.

Notary Public, Georgia State at Large
My Commission Expires: 1/8/2023

LISA D. PARKER
NOTARY
EXPIRES
GEORGIA
January 8, 2023
PUBLIC
BARTOW COUNTY

BEFORE THE PUBLIC SERVICE COMMISSION
IN THE MATTER OF
BIG RIVERS ELECTRIC CORPORATION
APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-269

VERIFICATION

I, Chris Dawson, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

Chris Dawson

Chris Dawson

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN to before me by Chris Dawson on this the 10th day of August, 2020.

Lisa Parker

Notary Public, Georgia State at Large
My Commission Expires: 1/8/2023

LISA D. PARKER
NOTARY
EXPIRES
GEORGIA
January 8, 2023
PUBLIC
BARTOW COUNTY

BEFORE THE PUBLIC SERVICE COMMISSION
IN THE MATTER OF
BIG RIVERS ELECTRIC CORPORATION
APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-269

VERIFICATION

I, Christopher Heimgartner, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

Christopher Heimgartner

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN to before me by Christopher Heimgartner on this the 10th day of August, 2020.

TAMMY KONSLER
NOTARY PUBLIC
ID NO. 579781
MY COMMISSION EXPIRES 5/28/2021
STATE AT LARGE, KY.

Tammy Konsler
Notary Public, Kentucky State at Large
My Commission Expires: 5-28-2021
Notary ID #: 579781

BEFORE THE PUBLIC SERVICE COMMISSION
IN THE MATTER OF
BIG RIVERS ELECTRIC CORPORATION
APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-269

VERIFICATION

I, Barbara Moll, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

Barbara A. Moll

Barbara Moll

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN to before me by Barbara Moll on this the 10th day of August, 2020.

TAMMY KONSLER NOTARY PUBLIC ID NO. 579781 MY COMMISSION EXPIRES 5/28/2021 STATE AT LARGE, KY.

Tammy Konsler
Notary Public, Kentucky State at Large
My Commission Expires: 5-28-2021
Notary ID #: 579781

Item 1) **Please provide a detailed listing of all amounts Henderson claims Big Rivers owes it as of the date of your response, and provide all supporting details, contract provisions, correspondence, workpapers, and other Documents. Provide any Excel files in Excel format with all formulas and links intact.**

Response) Please see attached "Overview Summary" reflecting total amount due from Big Rivers to Henderson to settle disputed operating costs reflected in past Station Two budgets and to settle all disputes concerning liability for variable costs and sales revenue associated with the generation of unprofitable and unwanted surplus energy and purported shortfalls in Henderson's supply of coal and lime used for the generation of unwanted energy and Henderson's native load. Settlement figures for the latter dispute are based on the assumption Henderson pays variable production costs and receives revenue associated with unwanted energy and writes off coal and lime inventory totaling $3,500,219 and currently reflected on Henderson's books. Please refer to the Moll Testimony and exhibits for other documentation supporting these calculations. All calculations are based upon figures provided by Big Rivers and all requested documents are in Big Rivers' possession.

Henderson Municipal Power & Light Overview Summary Amounts Due (To)/From Big Rivers June 2016 – January 2019		
Exhibit	**Description**	**Amount Due (To)/ From Big Rivers**
Exhibit Moll-3	Accounting Summary – Other Operating Costs	$6,359,736
Exhibit Moll-2	Unwanted Energy Net Revenue & Costs Associated with Energy Production	$1,233,584
	Total Due (To)/From Big Rivers	**$7,593,320**
Item 1 (Attached)	HMP&L Coal Write-off	($2,149,084)

Item 1 (Attached)	HMP&L Lime Write-off	($1,351,135
	Total HMP&L Inventory Write-off	**($3,500,219)**

Witness) **Barbara Moll**

Henderson Municipal Power & Light
Overview Summary
Amounts Due (To) / From Big Rivers
June 2016 - January 2019

Exhibit	Description	Amount Due (To) / From Henderson
Moll Testimony: Exhibit Moll-3	Accounting Summary - Other Operating Costs	$6,359,736
Moll Testimony: Exhibit Moll-2	Revenue and Costs Associated with Energy Production	$1,233,584
	Total Due (To) / From Big Rivers	**$7,593,320**
Item 1 (Attached)	HMP&L Write-Off of Inventory for Coal used in Energy Production	($2,149,084)
Item 1 (Attached)	HMP&L Write-Off of Inventory for Lime used in Energy Production	($1,351,135)
	Total Write-Off of HMP&L Inventory	**($3,500,219)**

EXHIBIT

Exhibit Moll-2

Big Rivers Electric Corporation
Summary of Revenue & Costs associated with Excess Henderson Energy*
June 2016 - January 2019

	HMPL Coal When Available	
Revenues:		
	MISO Rev for Unwanted EHE	$16,955,597.28
	BREC EHE Utilization ($1.50/MWh)	$88,191.00
	Subtotal EHE MISO Revenue	$17,043,788.28
Costs:		
	Coal Shortfall	($12,790,320.29)
	Lime Shortfall	($915,742.28)
	Fuel Oil	($1,489,602.65)
	2016 Coal Stock Pile Inventory Adj	($430,182.79)
	2018 Coal Stock Pile Inventory Adj	($124,300.00)
	2019 Coal Stock Pile Inventory Adj	($52,525.00)
	2019 Coal Stock Pile Inventory Survey Cost	($7,531.50)
	Subtotal Costs	($15,810,204.51)
	Net due HMPL	$1,233,583.77

	HMPL Share
Station II Coal Inventory Tons as of 03/31/19	-
Station II Lime Inventory Tons as of 03/31/19	481.00

Note:
* This summary excludes some expenses (Fixation Lime, Dredge, Sludge, Grit, etc) associated with Excess Henderson Energy which are part of the fiscal year end settlement process. Additionally, this summary excludes other costs including, but not limited to, capacity purchases ($203,655.82), transmission charges ($1,422,761.54) and auxiliary power.

Detailed Reconciliation Related to Revenue and Costs Associated with Energy Production
Exhibit Moll-2, Exhibit Smith-2, Exhibit Smith-3

	Smith Testimony	Moll Testimony	Difference	Note
Exhibit 2 - Excess Henderson Energy				
MISO Revenue	$ (6,259,439)	$ (16,955,597)	$ (10,696,158)	
Big Rivers EHE Utilization ($1.50/MWh)	$ -	$ (88,191)	$ (88,191)	
Coal Shortfall Supplied by Big Rivers	$ 2,301,641	$ 12,428,384	$ 10,126,743	1
Lime Shortfall Supplied by Big Rivers	$ -	$ 915,742	$ 915,742	1
Low Chlorine Coal Shortfall Supplied by Big Rivers	$ 213,023	$ 213,023	$ -	
Fuel Oil Supplied by Big Rivers	$ 371,131	$ 569,559	$ 198,428	2
2016 Coal Survey Adjustment Supplied by Big Rivers	$ -	$ 41,568	$ 41,568	
2018 Coal Survey Adjustment Supplied by Big Rivers	$ 39,384	$ -	$ (39,384)	3
2019 Coal Survey Adjustment Supplied by Big Rivers	$ 23,778	$ 23,778	$ -	
2019 Coal Stock Pile Inventory Survey Cost	$ -	$ 3,410	$ 3,410	4
Total - Exhibit 2	**$ (3,310,482)**	**$ (2,848,324)**	**$ 462,158**	
Exhibit 3 - Native Load				
Coal Shortfall Supplied by Big Rivers	$ 2,852,464	$ -	$ (2,852,464)	1
Low Chlorine Coal Shortfall Supplied by Big Rivers	$ 273,213	$ 273,213	$ -	
Lime Shortfall Supplied by Big Rivers	$ 145,588	$ -	$ (145,588)	1
Fuel Oil Supplied by Big Rivers	$ 920,044	$ 920,044	$ -	5
2016 Coal Survey Adjustment Supplied by Big Rivers	$ 388,615	$ 388,615	$ -	
2018 Coal Survey Adjustment Supplied by Big Rivers	$ 84,916	$ -	$ (84,916)	3
2019 Coal Survey Adjustment Supplied by Big Rivers	$ 28,747	$ 28,747	$ -	
2019 Coal Stock Pile Inventory Survey Costs	$ -	$ 4,122	$ 4,122	4
Total - Exhibit 3	**$ 4,693,587**	**$ 1,614,741**	**$ (3,078,846)**	
GRAND TOTAL	**$ 1,383,105**	**$ (1,233,583)**	**$ (2,616,688)**	

*****Negative amounts due to HMPL, positive amounts due to Big Rivers***
*****Moll Exhibit-2 originally prepared by Big Rivers***

1) Included all coal and lime due to Big Rivers as related to Excess Henderson Energy. This was due to the fact that HMP&L had enough coal and lime to meet its Native Load needs, but would not have had enough coal and lime to meet the needs for the production of any Excess Henderson Energy. However, the totals will be the same regardless of the allocation.
2) My calculations had $569,426, but I used Big Rivers's amount since it was close and it was calculated by Big Rivers
3) The 2018 Coal Stock Pile Inventory Adj is already included in the $12,428,284 due to Big Rivers in "Coal Shortfall Supplied by Big Rivers."
Detail:

Total Coal Due to Big Rivers as listed on the Excess Energy Invoices:	$	12,428,384
Low Chlorine Coal - Excess Henderson Energy:	$	213,023
Low Chlorine Coal - Native Load:	$	273,213
Total Included in this Reconciliation	$	12,914,620
Coal Shortfall per Exhibit Moll-2:	$	12,790,320
2018 Coal Stock Pile Inventory Adj per Exhibit Moll-2:	$	124,300
Total per Exhibit Moll-2	$	12,914,620

See "Coal Inventory Summary" tab for more information regarding reconciliation of coal tons
4) Divided based on 2019 Coal Survey Adjustment allocation. This has already been paid by HMPL, however, to make the amounts match specifically to Big Rivers's documents, HMPL has included this amount.
5) My calculations had $920,176, but I used Big Rivers's amount since it was close and it was calculated by Big Rivers

Accounting Summary
Henderson Municipal Power & Light
Amounts Due (To) / From BREC
Other Operating Costs

FY 2015 2016			
	Vertical Expansion Wall Charges	$	352,526
	Total FY 2015 - 2016 Amount Due (To) / From BREC	$	352,526
FY 2016 - 2017			
	Vertical Expansion Wall Charges	$	728,695
	Total FY 2016 - 2017 Amount Due (To) / From BREC	$	728,695
FY 2017 - 2018			
	Budget Reconciliation	$	1,649,923
	Add: MISO Fees	$	275,193
	Add: Vertical Expansion Wall Charges	$	386,361
(A)	**Total FY 2017-2018 Amount Due (To) / From BREC**	$	2,311,477
FY 2018 - 2019			
	Budget Reconciliation	$	672,056
	Severance Cost Adjustment - from Budget to Actual at 125 MW Split [1]	$	143,400
	Add: Severance Costs - Actual Amount Included at 125 MW Split [1]	$	1,201,510
	Add: MISO Fees	$	203,636
	Add: Vertical Expansion Wall Charges	$	287,992
	Add: 115 MW Split Difference	$	561,522
(B)	**Total FY 2018-2019 Amount Due (To) / From BREC**	$	3,070,116
Auxiliary Power			
	June - October 2018	$	(10,334)
	November 2018	$	(16,455)
	December 2018	$	(12,711)
	January 2019	$	(25,066)
(C)	**Total Auxiliary Power Due (To) / From BREC**	$	(64,566)
MISO Fees (December 2010 - May 2016)		$	(38,512)
(D)	**Total MISO Fees Due (To) / From BREC**	$	(38,512)
Grand Total Net Due (To) / From BREC [(A) + (B) + (C) + (D)]		$	6,359,736

[1] Per BREC's Response to Commission Staff's Initial Request for Information dated June 8, 2020 Item #5.

Exhibit Moll-3

Disposal Cost Analysis

	FY 2014-2015	FY 2015-2016	FY 2016-2017	FY 2017-2018	FY 2018-2019
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1514	0.1454	0.1448	0.2005	0.1999
Bottom Ash - Tons / Gross MWH	0.0098	0.0091	0.0091	0.0086	0.0086
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.78	$ 5.61	$ 6.85	$ 5.85	$ 5.85
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.78	$ 5.61	$ 6.85	$ 5.85	$ 5.85
Increase from base cost of $1.78/ton, assumed to be entirely related to construction of vertical expansion wall		$ 3.83	$ 5.07	$ 4.07	$ 4.07

*FY 2018-2019: estimated the breakdown between categories, but rate is correct in total

	FY 2014-2015	FY 2015-2016	FY 2016-2017	FY 2017-2018	FY 2018-2019
MWH - Native Load		595,749	592,892	311,898	204,635
MWH - UEHE		-	341,006	142,090	134,740
Tons of Disposal - Pozatec/Ash - Flyash - Native Load		86,622	85,851	62,536	40,907
Tons of Disposal - Bottom Ash - Native Load		5,421	5,395	2,682	1,760
Tons of Disposal - Pozatec/Ash - Flyash - UEHE		-	49,378	28,489	26,935
Tons of Disposal - Bottom Ash - UEHE		-	3,103	1,222	1,159
		92,043	143,727	94,929	70,760
Total Amount Due to HMPL for Reimbursement of Previously Paid Vertical Expansion Wall Charges	N/A	$ 352,525.53	$ 728,695.39	$ 386,360.59	$ 287,991.93

Henderson Station Two
2017 / 2018 Operating Plan
FGD System Costs

	Jun '17	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Jan '18	Feb '18	Mar '18	Apr '18	May '18	FYE 17/18
NET GENERATION (MWH)													
STATION TWO:	177,391	191,321	189,182	175,661	185,033	178,056	191,504	214,687	193,180	209,903	195,596	196,458	2,297,972
BREC:	100,319	115,796	112,662	97,242	107,080	104,563	117,730	156,079	136,368	147,693	132,205	127,948	1,455,685
HMP&L	77,072	75,525	76,520	78,419	77,953	73,493	73,774	58,608	56,812	62,210	63,391	68,510	842,287
GREEN:	239,487	262,757	260,250	224,414	252,553	240,643	273,366	324,076	288,853	298,974	261,466	255,986	3,182,825
DISPOSAL (TONS)													
STATION TWO:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	35,565	38,358	37,929	35,219	37,097	35,699	38,395	43,043	38,731	42,084	39,215	39,388	460,723
Bottom Ash - Tons / Gross MWH	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	
Bottom Ash - Tons of Disposal	1,518	1,638	1,619	1,503	1,584	1,524	1,639	1,838	1,653	1,797	1,674	1,681	19,668
STATION TWO Gross Tons of Disposal	37,083	39,996	39,548	36,722	38,681	37,223	40,034	44,881	40,384	43,881	40,889	41,069	480,391
BREC:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	20,113	23,216	22,588	19,496	21,468	20,964	23,604	31,293	27,341	29,611	26,506	25,652	291,852
Bottom Ash - Tons / Gross MWH	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	
Bottom Ash - Tons of Disposal	858	991	964	832	917	895	1,008	1,336	1,167	1,264	1,131	1,095	12,458
BREC Gross Tons of Disposal	20,971	24,207	23,552	20,328	22,385	21,859	24,612	32,629	28,508	30,875	27,637	26,747	304,310
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	
BREC DISPOSAL COSTS	$ 122,680	$ 141,611	$ 137,779	$ 118,919	$ 130,952	$ 127,875	$ 143,980	$ 190,880	$ 166,772	$ 180,619	$ 161,676	$ 156,470	$ 1,780,213
HMP&L:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	0.2005	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	15,452	15,142	15,341	15,723	15,629	14,735	14,791	11,750	11,390	12,473	12,709	13,736	168,871
Bottom Ash - Tons / Gross MWH	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	0.0086	
Bottom Ash - Tons of Disposal	660	647	655	671	667	629	631	502	486	533	543	586	7,210
HMP&L Gross Tons of Disposal	16,112	15,789	15,996	16,394	16,296	15,364	15,422	12,252	11,876	13,006	13,252	14,322	176,081
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	$ 5.850	
Landfill (Pozatec/Ash Disposal) - HMPL Only	$ 94,255	$ 92,366	$ 93,577	$ 95,905	$ 95,332	$ 89,879	$ 90,219	$ 71,674	$ 69,475	$ 76,085	$ 77,524	$ 83,784	$ 1,030,075
Landfill Usage Fee (per ton) - HMPL Only	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	
Landfill Usage Fee - HMPL Only	$ 17,353	$ 17,005	$ 17,228	$ 17,656	$ 17,551	$ 16,547	$ 16,609	$ 13,195	$ 12,790	$ 14,007	$ 14,272	$ 15,425	$ 189,638
HMP&L DISPOSAL COSTS	$ 111,608	$ 109,371	$ 110,805	$ 113,561	$ 112,883	$ 106,426	$ 106,828	$ 84,869	$ 82,265	$ 90,092	$ 91,796	$ 99,209	$ 1,219,713
Station Two DISPOSAL COSTS	$ 234,288	$ 250,982	$ 248,584	$ 232,480	$ 243,835	$ 234,301	$ 250,808	$ 275,749	$ 249,037	$ 270,711	$ 253,472	$ 255,679	$ 2,999,926

Henderson Station Two
2017 / 2018 Operating Plan
FGD System Costs

	Jun '17	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Jan '18	Feb '18	Mar '18	Apr '18	May '18	FYE 17/18
GREEN:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	41,107	45,101	44,671	38,520	43,350	41,306	46,922	55,627	49,581	51,318	44,880	43,939	546,322
Bottom Ash - Tons / Gross MWH	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	
Bottom Ash - Tons of Disposal	1,907	2,092	2,072	1,787	2,011	1,916	2,177	2,581	2,300	2,381	2,082	2,038	25,344
GREEN Gross Tons of Disposal	**43,014**	**47,193**	**46,743**	**40,307**	**45,361**	**43,222**	**49,099**	**58,208**	**51,881**	**53,699**	**46,962**	**45,977**	**571,666**
STATION TWO & GREEN Gross Tons of Disposal	**80,097**	**87,189**	**86,291**	**77,029**	**84,042**	**80,445**	**89,133**	**103,089**	**92,265**	**97,580**	**87,851**	**87,046**	**1,052,057**
Station II % of Total Site Disposal	46.3%	45.9%	45.8%	47.7%	46.0%	46.3%	44.9%	43.5%	43.8%	45.0%	46.5%	47.2%	
FGD SYSTEM COST													
Shared FGD System - Disposal Allocation:													
Fixation Lime - Green	$ 83,251	$ 91,340	$ 90,468	$ 78,011	$ 87,792	$ 83,652	$ 95,028	$ 114,852	$ 102,369	$ 105,956	$ 92,663	$ 90,721	$ 1,116,103
Fixation Lime - SII	67,583	72,891	72,076	66,924	70,495	67,837	72,960	83,386	75,033	81,528	75,971	76,306	882,990
Ash Pond Dredging - SII	-	-	-	52,500	52,500	-	-	-	-	-	-	-	105,000
Landfill CQA/CQC Costs	4,300	4,300	4,300	4,300	4,300	4,300	-	-	-	4,300	4,300	4,300	38,700
Landfill Conditioning	2,000	2,000	2,000	2,000	2,000	2,000	-	-	-	2,000	2,000	2,000	18,000
Sodium Bisulfite - Green	3,942	4,325	4,284	3,694	4,157	3,961	4,500	5,335	4,755	4,921	4,304	4,214	52,393
Subtotal Shared FGD System - Disposal Alloc	**161,076**	**174,856**	**173,128**	**207,429**	**221,245**	**161,750**	**172,487**	**203,573**	**182,157**	**198,706**	**179,239**	**177,541**	**2,213,187**
Station II % of Total Site Disposal	46.3%	45.9%	45.8%	47.7%	46.0%	46.3%	44.9%	43.5%	43.8%	45.0%	46.5%	47.2%	
STATION TWO Portion of Disposal	**$ 74,574**	**$ 80,211**	**$ 79,346**	**$ 98,888**	**$ 101,830**	**$ 74,844**	**$ 77,473**	**$ 88,628**	**$ 79,729**	**$ 89,357**	**$ 83,424**	**$ 83,765**	**$ 1,012,069**
Ammonia - SII	43,701	47,133	46,606	43,275	45,584	43,865	47,178	52,889	47,591	51,711	48,186	48,399	566,118
Emulsified Sulfur - SII	16,015	17,273	17,080	15,859	16,705	16,075	17,290	19,383	17,441	18,951	17,659	17,737	207,469
Air Emission Fees - SII	35,343	35,343	35,343	35,343	35,343	35,343	35,343	31,050	31,050	31,050	31,050	31,050	402,651
FGD System Amortization	8,179	8,179	8,179	8,179	8,179	8,179	8,179	4,794	4,794	4,794	4,794	4,794	81,223
Station Two Total - FGD System Cost	**$ 177,813**	**$ 188,139**	**$ 186,554**	**$ 201,544**	**$ 207,641**	**$ 178,307**	**$ 185,463**	**$ 196,744**	**$ 180,605**	**$ 195,863**	**$ 185,113**	**$ 185,744**	**$ 2,269,530**
TOTAL FGD SYSTEM & DISPOSAL COST													
Station Two Total Reagent Costs	**$ 412,101**	**$ 439,121**	**$ 435,138**	**$ 434,024**	**$ 451,476**	**$ 412,608**	**$ 436,271**	**$ 472,493**	**$ 429,642**	**$ 466,574**	**$ 438,585**	**$ 441,423**	**$ 5,269,456**
BREC Allocation of Reagent Costs	**$ 234,953**	**$ 260,404**	**$ 255,571**	**$ 246,176**	**$ 262,059**	**$ 240,460**	**$ 261,083**	**$ 315,106**	**$ 280,808**	**$ 304,289**	**$ 278,558**	**$ 273,751**	**$ 3,213,218**
HMP&L Allocation of Reagent Costs	**$ 177,148**	**$ 178,717**	**$ 179,567**	**$ 187,848**	**$ 189,417**	**$ 172,148**	**$ 175,188**	**$ 157,387**	**$ 148,834**	**$ 162,285**	**$ 160,027**	**$ 167,672**	**$ 2,056,238**

Station II
Reagent Costs
2011 / 2012 Operating Plan

	Jun '11	Jul '11	Aug '11	Sep '11	Oct '11	Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Total
GROSS GENERATION (MWH)													
STATION TWO:	205,616	216,106	218,309	207,484	210,918	206,774	216,581	218,095	207,972	212,007	102,610	149,976	2,372,447
BREC:	155,444	158,253	158,279	157,307	160,738	156,600	169,681	166,828	161,067	165,097	53,507	91,645	1,754,446
HMP&L	57,824	65,505	67,682	57,829	57,832	57,826	54,552	58,920	54,558	54,561	56,754	65,985	709,827
Adjusted per HMP&L's Request	(7,652)	(7,652)	(7,652)	(7,652)	(7,652)	(7,652)	(7,652)	(7,652)	(7,652)	(7,652)	(7,652)	(7,655)	(91,827)
HMP&L (Projected):	50,172	57,853	60,030	50,177	50,180	50,174	46,900	51,268	46,906	46,909	49,102	58,330	618,000
GREEN:	305,412	320,602	326,083	309,397	196,014	224,612	326,907	334,402	317,132	328,667	308,446	251,309	3,548,985
DISPOSAL (TONS)													
STATION TWO:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	30,946	32,525	32,856	31,227	31,744	31,120	32,596	32,824	31,301	31,908	15,443	22,572	357,062
Bottom Ash - Tons / Gross MWH	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	
Bottom Ash - Tons of Disposal	1,905	2,002	2,023	1,923	1,954	1,916	2,007	2,021	1,927	1,964	951	1,390	21,984
STATION TWO Gross Tons of Disposal	**32,851**	**34,527**	**34,879**	**33,150**	**33,698**	**33,036**	**34,603**	**34,845**	**33,228**	**33,872**	**16,394**	**23,962**	**379,046**
BREC:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	23,395	23,818	23,822	23,675	24,192	23,569	25,538	25,108	24,241	24,848	8,053	13,793	264,051
Bottom Ash - Tons / Gross MWH	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	
Bottom Ash - Tons of Disposal	1,440	1,466	1,467	1,458	1,489	1,451	1,572	1,546	1,492	1,530	496	849	16,257
BREC Gross Tons of Disposal	**24,835**	**25,284**	**25,288**	**25,133**	**25,681**	**25,020**	**27,110**	**26,654**	**25,734**	**26,378**	**8,549**	**14,642**	**280,308**
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
BREC DISPOSAL COSTS	**$ 42,717**	**$ 43,489**	**$ 43,496**	**$ 43,229**	**$ 44,172**	**$ 43,034**	**$ 46,629**	**$ 47,444**	**$ 45,806**	**$ 46,952**	**$ 15,217**	**$ 26,063**	**$ 488,248**
HMP&L:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	0.1505	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	7,551	8,707	9,035	7,552	7,552	7,551	7,059	7,716	7,059	7,060	7,390	8,779	93,011
Bottom Ash - Tons / Gross MWH	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	
Bottom Ash - Tons of Disposal	465	536	556	465	465	465	435	475	435	435	455	541	5,727
HMP&L Gross Tons of Disposal	**8,016**	**9,243**	**9,591**	**8,017**	**8,017**	**8,016**	**7,493**	**8,191**	**7,494**	**7,495**	**7,845**	**9,319**	**98,738**
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.720	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill (Pozatec/Ash Disposal) - HMPL Only	**$ 13,788**	**$ 15,898**	**$ 16,496**	**$ 13,789**	**$ 13,790**	**$ 13,788**	**$ 12,888**	**$ 14,580**	**$ 13,340**	**$ 13,341**	**$ 13,964**	**$ 16,589**	**$ 172,251**
Landfill Usage Fee (per ton) - HMPL Only	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	
Landfill Usage Fee - HMPL Only	**$ 8,633**	**$ 9,955**	**$ 10,329**	**$ 8,634**	**$ 8,635**	**$ 8,634**	**$ 8,070**	**$ 8,822**	**$ 8,071**	**$ 8,072**	**$ 8,449**	**$ 10,037**	**$ 106,341**
HMP&L DISPOSAL COSTS	**$ 22,422**	**$ 25,854**	**$ 26,826**	**$ 22,424**	**$ 22,426**	**$ 22,423**	**$ 20,959**	**$ 23,403**	**$ 21,412**	**$ 21,414**	**$ 22,414**	**$ 26,627**	**$ 278,604**

Station II
Reagent Costs
2011 / 2012 Operating Plan

	Jun '11	Jul '11	Aug '11	Sep '11	Oct '11	Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Total
GREEN:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1730	0.1730	0.1730	0.1730	0.1730	0.1730	0.1730	0.1730	0.1730	0.1730	0.1730	0.1730	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	52,844	55,472	56,421	53,534	33,915	38,864	56,563	57,860	54,872	56,868	53,369	43,483	614,065
Bottom Ash - Tons / Gross MWH	0.0121	0.0121	0.0121	0.0121	0.0121	0.0121	0.0121	0.0121	0.0121	0.0121	0.0121	0.0121	
Bottom Ash - Tons of Disposal	3,683	3,866	3,932	3,731	2,364	2,709	3,942	4,032	3,824	3,963	3,719	3,030	42,796
GREEN Gross Tons of Disposal	**56,527**	**59,338**	**60,353**	**57,264**	**36,279**	**41,572**	**60,505**	**61,893**	**58,696**	**60,831**	**57,088**	**46,513**	**656,861**
STATION TWO & GREEN Gross Tons of Disposal	**89,378**	**93,866**	**95,232**	**90,414**	**69,977**	**74,608**	**95,108**	**96,738**	**91,924**	**94,703**	**73,482**	**70,475**	**1,035,907**
Station II % of Total Site Disposal	36.8%	36.8%	36.6%	36.7%	48.2%	44.3%	36.4%	36.0%	36.1%	35.8%	22.3%	34.0%	

FGD SYSTEM COST

	Jun '11	Jul '11	Aug '11	Sep '11	Oct '11	Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Total
Shared FGD System - Disposal Allocation:													
Fixation Lime - Green	$ 78,849	$ 82,771	$ 84,186	$ 79,878	$ 50,606	$ 57,989	$ 84,399	$ 86,334	$ 81,875	$ 84,853	$ 79,633	$ 70,031	$ 921,405
Fixation Lime - SII	45,001	47,297	47,779	45,410	46,162	45,255	47,401	47,733	45,517	46,400	22,457	35,429	521,843
Ash Pond Dredging - SII	-	100,000	100,000	-	-	-	-	-	-	-	-	-	200,000
Sodium Bisulfite - Green	7,130	7,485	7,613	7,223	4,576	5,244	7,632	8,041	7,626	7,903	7,417	6,043	83,932
Sodium Bisulfite - SII	5,249	5,517	5,573	5,297	5,384	5,279	5,529	5,731	5,465	5,571	2,696	3,941	61,231
Total Shared FGD System - Disposal Allocation	**136,230**	**243,070**	**245,151**	**137,808**	**106,728**	**113,766**	**144,961**	**147,838**	**140,483**	**144,727**	**112,203**	**115,444**	**1,788,411**
Station II % of Total Site Disposal	36.8%	36.8%	36.6%	36.7%	48.2%	44.3%	36.4%	36.0%	36.1%	35.8%	22.3%	34.0%	
STATION TWO Portion of Disposal	**$ 50,072**	**$ 89,410**	**$ 89,788**	**$ 50,526**	**$ 51,396**	**$ 50,375**	**$ 52,741**	**$ 53,252**	**$ 50,780**	**$ 51,764**	**$ 25,033**	**$ 39,251**	**$ 654,388**
SCR/Scrubber Reagents:													
Ammonia - SII	88,757	94,515	96,490	92,296	95,573	98,235	108,353	112,834	106,633	105,806	47,638	69,714	1,116,846
Emulsified Sulfur - SII (Adjust to $8k/month per HMPL requ	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	96,000
STATION TWO SCR/Scrubber Reagents	**$ 96,757**	**$ 102,515**	**$ 104,490**	**$ 100,296**	**$ 103,573**	**$ 106,235**	**$ 116,353**	**$ 120,834**	**$ 114,633**	**$ 113,806**	**$ 55,638**	**$ 77,714**	**$1,212,846**
Emission Controls: Air Emission Fees	**21,265**	**21,973**	**21,973**	**21,265**	**21,973**	**21,265**	**21,973**	**22,412**	**20,244**	**22,412**	**21,690**	**22,412**	**260,857**
FGD System Amortization	**31,869**	**31,869**	**31,869**	**31,869**	**31,869**	**31,869**	**31,869**	**28,485**	**28,485**	**28,485**	**28,485**	**28,485**	**365,508**
Total Station Two FGD System Cost	**$ 199,963**	**$ 245,767**	**$ 248,120**	**$ 203,956**	**$ 208,811**	**$ 209,744**	**$ 222,936**	**$ 224,983**	**$ 214,142**	**$ 216,467**	**$ 130,846**	**$ 167,862**	**$2,493,599**
BREC FGD System Cost @ 202 MW	**$ 129,463**	**$ 159,119**	**$ 160,642**	**$ 132,049**	**$ 135,192**	**$ 135,796**	**$ 144,337**	**$ 145,662**	**$ 138,643**	**$ 140,148**	**$ 84,715**	**$ 108,680**	**$1,614,446**
HMP&L FGD System Cost @ 110 MW	**$ 70,500**	**$ 86,649**	**$ 87,478**	**$ 71,908**	**$ 73,619**	**$ 73,948**	**$ 78,599**	**$ 79,321**	**$ 75,499**	**$ 76,318**	**$ 46,132**	**$ 59,182**	**$ 879,153**

TOTAL FGD SYSTEM & DISPOSAL COST

	Jun '11	Jul '11	Aug '11	Sep '11	Oct '11	Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12	Total
TOTAL STATION TWO	**$ 265,102**	**$ 315,110**	**$ 318,442**	**$ 269,609**	**$ 275,409**	**$ 275,201**	**$ 290,524**	**$ 295,830**	**$ 281,360**	**$ 284,833**	**$ 168,477**	**$ 220,552**	**$3,260,449**
BREC ALLOCATION	**$ 172,180**	**$ 202,608**	**$ 204,138**	**$ 175,278**	**$ 179,364**	**$ 178,830**	**$ 190,966**	**$ 193,106**	**$ 184,449**	**$ 187,100**	**$ 99,932**	**$ 134,743**	**$2,102,694**
HMP&L ALLOCATION	**$ 92,922**	**$ 112,502**	**$ 114,304**	**$ 94,331**	**$ 96,045**	**$ 96,371**	**$ 99,558**	**$ 102,724**	**$ 96,911**	**$ 97,733**	**$ 68,545**	**$ 85,809**	**$1,157,755**

Henderson Station Two
2013 / 2014 Operating Plan
Reagent Costs

	Jun '13	Jul '13	Aug '13	Sep '13	Oct '13	Nov '13	Dec '13	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Total
NET GENERATION (MWH)													
STATION TWO:	187,229	195,751	195,205	186,312	191,662	184,595	192,051	196,053	177,223	192,897	172,045	142,608	2,213,631
BREC:	130,736	137,278	133,726	133,821	145,990	140,840	142,703	143,382	129,328	145,223	128,302	94,914	1,606,243
HMP&L	56,493	58,473	61,479	52,491	45,672	43,755	49,348	52,671	47,895	47,674	43,743	47,694	607,388
GREEN:	277,737	292,440	292,681	276,234	292,296	281,727	293,488	299,352	269,422	206,436	244,865	290,593	3,317,271
DISPOSAL (TONS)													
STATION TWO:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1541	0.1541	0.2230	0.2387	0.1538	0.1537	0.1540	0.1680	0.1670	0.1673	0.1671	0.1677	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	28,849	30,164	43,529	44,472	29,484	28,364	29,572	32,933	29,596	32,280	28,753	23,918	381,914
Bottom Ash - Tons / Gross MWH	0.0100	0.0100	0.1212	0.1484	0.0099	0.0099	0.0100	0.0116	0.0115	0.0115	0.0115	0.0116	
Bottom Ash - Tons of Disposal	1,864	1,949	23,664	27,656	1,905	1,833	1,911	2,272	2,041	2,227	1,983	1,650	70,955
STATION TWO Gross Tons of Disposal	**30,713**	**32,113**	**67,193**	**72,128**	**31,389**	**30,197**	**31,483**	**35,205**	**31,637**	**34,507**	**30,736**	**25,568**	**452,869**
BREC:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1541	0.1541	0.2230	0.2387	0.1538	0.1537	0.1540	0.1680	0.1670	0.1673	0.1671	0.1677	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	20,144	21,154	29,820	31,943	22,458	21,641	21,973	24,085	21,598	24,302	21,442	15,919	276,479
Bottom Ash - Tons / Gross MWH	0.0100	0.0100	0.1212	0.1484	0.0099	0.0099	0.0100	0.0116	0.0115	0.0115	0.0115	0.0116	
Bottom Ash - Tons of Disposal	1,302	1,367	16,211	19,864	1,451	1,399	1,420	1,662	1,489	1,677	1,479	1,098	50,419
BREC Gross Tons of Disposal	**21,446**	**22,521**	**46,031**	**51,807**	**23,909**	**23,040**	**23,393**	**25,747**	**23,087**	**25,979**	**22,921**	**17,017**	**326,898**
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
BREC DISPOSAL COSTS	**$ 38,174**	**$ 40,087**	**$ 81,935**	**$ 92,216**	**$ 42,558**	**$ 41,011**	**$ 41,640**	**$ 45,830**	**$ 41,095**	**$ 46,243**	**$ 40,799**	**$ 30,290**	**$ 581,878**
HMP&L:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1541	0.1541	0.2230	0.2387	0.1538	0.1537	0.1540	0.1680	0.1670	0.1673	0.1671	0.1677	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	8,705	9,010	13,709	12,529	7,026	6,723	7,599	8,848	7,998	7,978	7,311	7,999	105,435
Bottom Ash - Tons / Gross MWH	0.0100	0.0100	0.1212	0.1484	0.0099	0.0099	0.0100	0.0116	0.0115	0.0115	0.0115	0.0116	
Bottom Ash - Tons of Disposal	562	582	7,453	7,792	454	434	491	610	552	550	504	552	20,536
HMP&L Gross Tons of Disposal	**9,267**	**9,592**	**21,162**	**20,321**	**7,480**	**7,157**	**8,090**	**9,458**	**8,550**	**8,528**	**7,815**	**8,551**	**125,971**
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill (Pozatec/Ash Disposal) - HMPL Only	**$ 16,495**	**$ 17,074**	**$ 37,668**	**$ 36,171**	**$ 13,314**	**$ 12,739**	**$ 14,400**	**$ 16,835**	**$ 15,219**	**$ 15,180**	**$ 13,911**	**$ 15,221**	**$ 224,227**
Landfill Usage Fee (per ton) - HMPL Only	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	
Landfill Usage Fee - HMPL Only	**$ 9,981**	**$ 10,331**	**$ 22,791**	**$ 21,886**	**$ 8,056**	**$ 7,708**	**$ 8,713**	**$ 10,186**	**$ 9,208**	**$ 9,185**	**$ 8,417**	**$ 9,209**	**$ 135,671**
HMP&L DISPOSAL COSTS	**$ 26,476**	**$ 27,405**	**$ 60,459**	**$ 58,057**	**$ 21,370**	**$ 20,447**	**$ 23,113**	**$ 27,021**	**$ 24,427**	**$ 24,365**	**$ 22,328**	**$ 24,430**	**$ 359,898**

Henderson Station Two
2013 / 2014 Operating Plan
Reagent Costs

	Jun '13	Jul '13	Aug '13	Sep '13	Oct '13	Nov '13	Dec '13	Jan '14	Feb '14	Mar '14	Apr '14	May '14	Total
GREEN:			Increased due to Landfill Capping										
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1650	0.1650	0.1650	0.1650	0.1650	0.1650	0.1650	0.1677	0.1677	0.1677	0.1677	0.1677	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	45,838	48,265	48,305	45,590	48,241	46,497	48,438	50,213	45,192	34,627	41,073	48,744	551,023
Bottom Ash - Tons / Gross MWH	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0104	0.0104	0.0104	0.0104	0.0104	
Bottom Ash - Tons of Disposal	3,199	3,368	3,371	3,181	3,366	3,245	3,380	3,128	2,815	2,157	2,558	3,036	36,804
GREEN Gross Tons of Disposal	49,037	51,633	51,676	48,771	51,607	49,742	51,818	53,341	48,007	36,784	43,631	51,780	587,827
STATION TWO & GREEN Gross Tons of Disposal	79,750	83,746	118,869	120,899	82,996	79,939	83,301	88,546	79,644	71,291	74,367	77,348	1,040,696
Station II % of Total Site Disposal	38.5%	38.3%	56.5%	59.7%	37.8%	37.8%	37.8%	39.8%	39.7%	48.4%	41.3%	33.1%	
FGD SYSTEM COST													
Shared FGD System - Disposal Allocation:													
Fixation Lime - Green	$ 72,893	$ 76,752	$ 76,815	$ 72,499	$ 76,714	$ 73,940	$ 77,027	$ 79,791	$ 71,813	$ 55,025	$ 65,268	$ 77,456	$ 875,995
Fixation Lime - SII	45,135	47,192	47,234	44,776	46,128	44,376	46,266	53,452	48,036	52,394	46,668	38,821	560,480
Ash Pond Dredging - SII	-	-	52,500	52,500	-	-	-	-	-	-	-	-	105,000
Sodium Bisulfite - Green	5,373	5,658	5,662	5,344	5,655	5,450	5,678	5,791	5,212	3,994	4,737	5,622	64,176
Sodium Bisulfite - SII	3,664	3,831	3,835	3,635	3,745	3,602	3,756	3,807	3,421	3,731	3,323	2,765	43,115
Total Shared FGD System - Disposal Allocation	127,066	133,433	186,046	178,754	132,242	127,369	132,727	142,841	128,483	115,143	119,997	124,664	1,648,765
Station II % of Total Site Disposal	38.5%	38.3%	56.5%	59.7%	37.8%	37.8%	37.8%	39.8%	39.7%	48.4%	41.3%	33.1%	
STATION TWO Portion of Disposal	$ 48,935	$ 51,166	$ 105,166	$ 106,644	$ 50,014	$ 48,114	$ 50,163	$ 56,792	$ 51,037	$ 55,733	$ 49,595	$ 41,209	$ 714,568
SCR/Scrubber Reagents:													
Ammonia - SII	$ 111,279	$ 116,351	$ 116,453	$ 110,394	$ 113,728	$ 109,407	$ 114,068	$ 99,406	$ 89,334	$ 97,438	$ 86,790	$ 72,196	$1,236,845
Emulsified Sulfur - SII	13,130	13,729	13,741	13,026	13,419	12,909	13,459	13,889	12,481	13,614	12,126	10,087	155,612
STATION TWO SCR/Scrubber Reagents	$ 124,410	$ 130,080	$ 130,194	$ 123,420	$ 127,147	$ 122,316	$ 127,528	$ 113,295	$ 101,816	$ 111,051	$ 98,917	$ 82,283	$1,392,457
Emission Controls: Air Emission Fees	15,627	15,627	15,627	15,627	15,627	15,627	15,618	16,803	16,803	16,803	16,803	16,803	193,395
FGD System Amortization	25,100	25,100	25,100	25,100	25,100	25,100	25,100	21,716	21,716	21,716	21,716	21,716	284,280
Total Station Two FGD System Cost	$ 214,072	$ 221,973	$ 276,087	$ 270,791	$ 217,888	$ 211,157	$ 218,409	$ 208,606	$ 191,372	$ 205,303	$187,031	$162,011	$2,584,700
BREC FGD System Cost @ 197 MW	$ 135,167	$ 140,156	$ 174,324	$ 170,980	$ 137,577	$ 133,327	$ 137,906	$ 131,716	$ 120,834	$ 129,630	$118,093	$102,295	$1,632,005
HMP&L FGD System Cost @ 115 MW	$ 78,905	$ 81,817	$ 101,763	$ 99,811	$ 80,311	$ 77,830	$ 80,503	$ 76,890	$ 70,538	$ 75,673	$ 68,938	$ 59,716	$ 952,695
TOTAL FGD SYSTEM & DISPOSAL COST													
Total Station Two Reagent Costs	$ 278,722	$ 289,465	$ 418,481	$ 421,064	$ 281,816	$ 272,615	$ 283,162	$ 281,457	$ 256,894	$ 275,911	$250,158	$216,731	$3,526,476
BREC Allocation of Reagent Costs	$ 173,341	$ 180,243	$ 256,259	$ 263,196	$ 180,135	$ 174,338	$ 179,546	$ 177,546	$ 161,929	$ 175,873	$158,892	$132,585	$2,213,883
HMP&L Allocation of Reagent Costs	$ 105,381	$ 109,222	$ 162,222	$ 157,868	$ 101,681	$ 98,277	$ 103,616	$ 103,911	$ 94,965	$ 100,038	$ 91,266	$ 84,146	$1,312,593

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Henderson Station Two
2018 / 2019 Operating Plan
Variable Costs

	Jun '18	Jul '18	Aug '18	Sep '18	Oct '18	Nov '18	Dec '18	Jan '19	Feb '19	Mar '19	Apr '19	May '19	FYE 18/19
\et Generation (MWH)													
STATION TWO	43,808	111,069	77,147	14,801	5,027	0	9,703	173,222	134,013	103,010	5,081	74,895	751,776
BREC	16,960	45,196	28,540	5,238	829	0	1,337	91,604	69,293	44,741	952	29,500	334,190
HMP&L	26,848	65,873	48,607	9,563	4,198	0	8,366	81,618	64,720	58,269	4,129	45,395	417,586
GREEN	237,866	255,568	255,447	232,321	250,264	232,255	267,499	319,395	287,640	274,927	238,571	249,651	3,101,404
Gross Tons of Disposal													
STATION TWO	9,136	23,163	16,089	3,087	1,048	0	2,024	36,125	27,948	21,483	1,060	15,619	156,782
BREC	3,537	9,426	5,952	1,092	173	0	279	19,104	14,451	9,331	199	6,152	69,696
HMP&L	5,599	13,738	10,137	1,994	875	0	1,745	17,021	13,497	12,152	861	9,467	87,086
GREEN	43,534	46,774	46,752	42,519	45,803	42,507	48,958	58,456	52,644	50,317	43,663	45,691	567,618
STATION TWO & GREEN Total	**52,670**	**69,937**	**62,841**	**45,606**	**46,851**	**42,507**	**50,982**	**94,581**	**80,592**	**71,800**	**44,723**	**61,310**	**724,400**
Station Two % of Site Disposal	*17.3%*	*33.1%*	*25.6%*	*6.8%*	*2.2%*	*0.0%*	*4.0%*	*38.2%*	*34.7%*	*29.9%*	*2.4%*	*25.5%*	
						DISPOSAL COSTS							
Landfill Pozatec/Ash Disposal - $5.85/ton													
STATION TWO	$ 53,446	$ 135,504	$ 94,121	$ 18,059	$ 6,131	$ -	$ 11,840	$ 211,331	$ 163,496	$ 125,676	$ 6,201	$ 91,371	$ 917,176
BREC	$ 20,691	$ 55,142	$ 34,819	$ 6,388	$ 1,012	$ -	$ 1,632	$ 111,758	$ 84,538	$ 54,586	$ 1,164	$ 35,989	$ 407,719
HMP&L	$ 32,754	$ 80,367	$ 59,301	$ 11,665	$ 5,119	$ -	$ 10,208	$ 99,573	$ 78,957	$ 71,089	$ 5,037	$ 55,382	$ 509,452
Landfill Usage Fee - $1.077/ton													
HMP&L	$ 6,030	$ 14,796	$ 10,918	$ 2,148	$ 942	$ -	$ 1,879	$ 18,332	$ 14,536	$ 13,088	$ 927	$ 10,196	$ 93,792
DISPOSAL COSTS													
STATION TWO	**$ 59,476**	**$ 150,300**	**$ 105,039**	**$ 20,207**	**$ 7,073**	**$ -**	**$ 13,719**	**$ 229,663**	**$ 178,032**	**$ 138,764**	**$ 7,128**	**$101,567**	**$1,010,968**
BREC	**$ 20,691**	**$ 55,142**	**$ 34,819**	**$ 6,388**	**$ 1,012**	**$ -**	**$ 1,632**	**$ 111,758**	**$ 84,538**	**$ 54,586**	**$ 1,164**	**$ 35,989**	**$ 407,719**
HMP&L	**$ 38,784**	**$ 95,163**	**$ 70,219**	**$ 13,813**	**$ 6,061**	**$ -**	**$ 12,087**	**$ 117,905**	**$ 93,493**	**$ 84,177**	**$ 5,964**	**$ 65,578**	**$ 603,244**

Henderson Station Two
2018 / 2019 Operating Plan
Variable Costs

	Jun '18	Jul '18	Aug '18	Sep '18	Oct '18	Nov '18	Dec '18	Jan '19	Feb '19	Mar '19	Apr '19	May '19	FYE 18/19
REAGENTS & OTHER VARIABLE COSTS													
Shared FGD System													
Green Fixation Lime	$ 92,253	$ 99,118	$ 99,072	$ 90,103	$ 97,062	$ 90,077	$ 103,746	$ 126,825	$ 114,216	$ 109,168	$ 94,731	$ 99,131	$1,215,502
Green Sodium Bisulfite	9,119	9,798	9,793	8,907	9,595	8,904	10,255	12,498	11,256	10,758	9,336	9,769	119,988
STII Fixation Lime	19,466	49,354	34,281	6,577	2,234	-	4,312	78,807	60,969	46,864	2,311	34,073	339,248
STII Sodium Bisulfite	-	-	-	-	-	-	-	-	-	-	-	-	0
STII Ash Pond Dredging	-	-	52,500	52,500	-	-	-	-	-	-	-	-	105,000
STII Landfill	32,497	32,497	32,497	32,497	32,497	29,630	29,630	29,630	29,630	29,630	29,630	32,497	372,762
Total Shared FGD System Costs	**$ 153,335**	**$ 190,767**	**$ 228,143**	**$ 190,584**	**$ 141,388**	**$ 128,611**	**$ 147,943**	**$ 247,760**	**$ 216,071**	**$ 196,420**	**$136,008**	**$175,470**	**$2,152,500**
Station Two % of Site Disposal	17.3%	33.1%	25.6%	6.8%	2.2%	0.0%	4.0%	38.2%	34.7%	29.9%	2.4%	25.5%	
Total STATION TWO Shared Allocation	**$ 26,597**	**$ 63,182**	**$ 58,411**	**$ 12,900**	**$ 3,163**	**$ 0**	**$ 5,873**	**$ 94,631**	**$ 74,930**	**$ 58,770**	**$ 3,224**	**$ 44,702**	**$ 446,383**
Non-Shared Reagents & Other Costs													
STII Ammonia	$ 9,906	$ 25,115	$ 17,445	$ 3,347	$ 1,137	$ -	$ 2,194	$ 39,169	$ 30,303	$ 23,293	$ 1,149	$ 16,935	$ 169,993
STII Emulsified Sulfur	4,528	11,480	7,974	1,530	520	-	1,003	17,907	13,853	10,649	525	7,742	77,711
STII Air Emission Fees	27,451	27,451	27,451	27,451	27,451	27,451	27,451	27,451	27,451	27,451	27,451	27,451	329,412
STII FGD System Amortization	4,794	4,794	4,794	4,794	4,794	4,794	4,794	1,410	1,410	1,410	1,410	1,410	40,608
Total STATION TWO Non-Shared	**$ 46,679**	**$ 68,840**	**$ 57,664**	**$ 37,122**	**$ 33,902**	**$ 32,245**	**$ 35,442**	**$ 85,937**	**$ 73,017**	**$ 62,803**	**$ 30,535**	**$ 53,538**	**$ 617,724**
TOTAL REAGENTS & OTHER VARIABLE COSTS													
STATION TWO	**$ 73,276**	**$ 132,022**	**$ 116,075**	**$ 50,022**	**$ 37,065**	**$ 32,245**	**$ 41,315**	**$ 180,568**	**$ 147,947**	**$ 121,573**	**$ 33,759**	**$ 98,240**	**$1,064,107**
BREC @ 187 MW	$ 43,919	$ 79,129	$ 69,571	$ 29,981	$ 22,215	$ 19,326	$ 24,763	$ 108,225	$ 88,673	$ 72,866	$ 20,234	$ 58,881	$ 637,782
HMP&L @ 125 MW	$ 29,358	$ 52,888	$ 46,505	$ 20,047	$ 14,850	$ 12,919	$ 16,552	$ 72,343	$ 59,275	$ 48,708	$ 13,525	$ 39,359	$ 426,325
TOTAL VARIABLE COSTS													
STATION TWO	**$ 132,752**	**$ 282,322**	**$ 221,114**	**$ 70,229**	**$ 44,138**	**$ 32,245**	**$ 55,034**	**$ 410,231**	**$ 325,979**	**$ 260,337**	**$ 40,887**	**$199,807**	**$2,075,075**
BREC	**$ 64,610**	**$ 134,271**	**$ 104,390**	**$ 36,369**	**$ 23,227**	**$ 19,326**	**$ 26,395**	**$ 219,983**	**$ 173,211**	**$ 127,452**	**$ 21,398**	**$ 94,870**	**$1,045,502**
HMP&L	**$ 68,142**	**$ 148,051**	**$ 116,724**	**$ 33,860**	**$ 20,911**	**$ 12,919**	**$ 28,639**	**$ 190,248**	**$ 152,768**	**$ 132,885**	**$ 19,489**	**$104,937**	**$1,029,573**

Station II
Reagent Costs
2012 / 2013 Operating Plan

	Jun '12	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Jan '13	Feb '13	Mar '13	Apr '13	May '13	Total
NET GENERATION (MWH)													
STATION TWO:	174,376	198,541	200,273	188,429	183,716	183,740	199,259	200,745	176,396	183,369	94,751	135,926	2,119,521
BREC:	119,559	142,148	140,887	138,179	137,674	140,145	149,607	147,670	128,414	135,832	50,748	88,654	1,519,517
HMP&L	56,918	58,494	61,487	52,351	48,143	45,696	51,753	55,176	50,083	49,638	46,104	49,373	625,216
Adjusted per HMP&L's Request	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(25,210)
HMP&L (Projected):	54,817	56,393	59,386	50,250	46,042	43,595	49,652	53,075	47,982	47,537	44,003	47,272	600,004
GREEN:	221,785	297,756	297,665	237,420	245,677	246,320	314,232	312,672	249,849	252,831	244,964	252,247	3,173,417
DISPOSAL (TONS)													
STATION TWO:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1545	0.1545	0.1571	0.2093	0.3231	0.1545	0.1545	0.1548	0.1548	0.1548	0.1548	0.1548	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	26,948	30,683	31,460	39,429	59,359	28,395	30,794	31,072	27,303	28,383	14,666	21,039	369,533
Bottom Ash - Tons / Gross MWH	0.0100	0.0100	0.0100	0.1053	0.1021	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
Bottom Ash - Tons of Disposal	1,747	1,989	2,006	19,834	18,750	1,840	1,996	2,017	1,772	1,842	952	1,365	56,109
STATION TWO Gross Tons of Disposal	**28,695**	**32,671**	**33,466**	**59,264**	**78,109**	**30,236**	**32,789**	**33,089**	**29,075**	**30,225**	**15,618**	**22,405**	**425,642**
BREC:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1545	0.1545	0.1571	0.2093	0.3231	0.1545	0.1545	0.1548	0.1548	0.1548	0.1548	0.1548	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	18,477	21,968	22,131	28,914	44,483	21,658	23,120	22,857	19,877	21,025	7,855	13,722	266,088
Bottom Ash - Tons / Gross MWH	0.0100	0.0100	0.0100	0.1053	0.1021	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
Bottom Ash - Tons of Disposal	1,197	1,424	1,411	14,545	14,051	1,404	1,498	1,483	1,290	1,364	510	891	41,068
BREC Gross Tons of Disposal	**19,674**	**23,391**	**23,543**	**43,459**	**58,534**	**23,062**	**24,619**	**24,340**	**21,167**	**22,389**	**8,365**	**14,613**	**307,156**
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
BREC DISPOSAL COSTS	**$ 35,020**	**$ 41,637**	**$ 41,906**	**$ 77,358**	**$ 104,190**	**$ 41,050**	**$ 43,822**	**$ 43,326**	**$ 37,676**	**$ 39,853**	**$ 14,889**	**$ 26,011**	**$ 546,738**
HMP&L:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1545	0.1545	0.1571	0.2093	0.3231	0.1545	0.1545	0.1548	0.1548	0.1548	0.1548	0.1548	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	8,471	8,715	9,329	10,515	14,876	6,737	7,673	8,215	7,427	7,358	6,811	7,317	103,445
Bottom Ash - Tons / Gross MWH	0.0100	0.0100	0.0100	0.1053	0.1021	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	
Bottom Ash - Tons of Disposal	549	565	595	5,289	4,699	437	497	533	482	478	442	475	15,041
HMP&L Gross Tons of Disposal	**9,021**	**9,280**	**9,924**	**15,804**	**19,575**	**7,174**	**8,171**	**8,748**	**7,909**	**7,836**	**7,253**	**7,792**	**118,486**
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill (Pozatec/Ash Disposal) - HMPL Only	**$ 16,057**	**$ 16,518**	**$ 17,664**	**$ 28,132**	**$ 34,844**	**$ 12,769**	**$ 14,544**	**$ 15,572**	**$ 14,078**	**$ 13,947**	**$ 12,910**	**$ 13,869**	**$ 210,904**
Landfill Usage Fee (per ton) - HMPL Only	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	
Landfill Usage Fee - HMPL Only	**$ 9,715**	**$ 9,994**	**$ 10,688**	**$ 17,021**	**$ 21,083**	**$ 7,726**	**$ 8,800**	**$ 9,422**	**$ 8,518**	**$ 8,439**	**$ 7,812**	**$ 8,392**	**$ 127,610**
HMP&L DISPOSAL COSTS	**$ 25,773**	**$ 26,513**	**$ 28,353**	**$ 45,154**	**$ 55,928**	**$ 20,496**	**$ 23,345**	**$ 24,995**	**$ 22,597**	**$ 22,387**	**$ 20,723**	**$ 22,262**	**$ 338,526**

Station II
Reagent Costs
2012 / 2013 Operating Plan

	Jun '12	Jul '12	Aug '12	Sep '12	Oct '12	Nov '12	Dec '12	Jan '13	Feb '13	Mar '13	Apr '13	May '13	Total
GREEN:			Increased due to Landfill Capping										
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1943	0.1943	0.2837	0.2837	0.3137	0.1943	0.1943	0.1915	0.1915	0.1915	0.1915	0.1915	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	43,086	57,845	84,450	67,358	77,071	47,853	61,046	59,865	47,836	48,407	46,901	48,295	690,013
Bottom Ash - Tons / Gross MWH	0.0153	0.0153	0.0153	0.1318	0.1278	0.0153	0.0153	0.0152	0.0152	0.0152	0.0152	0.0152	
Bottom Ash - Tons of Disposal	3,402	4,568	4,566	31,280	31,407	3,779	4,820	4,748	3,794	3,839	3,720	3,830	103,754
GREEN Gross Tons of Disposal	**46,488**	**62,413**	**89,016**	**98,638**	**108,478**	**51,631**	**65,866**	**64,613**	**51,630**	**52,247**	**50,621**	**52,126**	**793,767**
STATION TWO & GREEN Gross Tons of Disposal	**75,183**	**95,084**	**122,482**	**157,902**	**186,587**	**81,867**	**98,656**	**97,701**	**80,706**	**82,471**	**66,239**	**74,531**	**1,219,409**
Station II % of Total Site Disposal	38.2%	34.4%	27.3%	37.5%	41.9%	36.9%	33.2%	33.9%	36.0%	36.6%	23.6%	30.1%	
FGD SYSTEM COST													
Shared FGD System - Disposal Allocation:													
Fixation Lime - Green	$ 70,092	$ 94,102	$ 94,073	$ 75,033	$ 77,643	$ 77,846	$ 99,308	$ 97,490	$ 77,902	$ 78,832	$ 76,379	$ 78,650	$ 997,350
Fixation Lime - SII	41,953	47,767	48,183	45,334	44,200	44,206	47,940	48,387	42,518	44,198	22,838	32,763	510,286
Sodium Bisulfite - Green	4,041	5,425	5,424	4,326	4,477	4,488	5,726	5,868	4,689	4,745	4,597	4,734	58,541
Sodium Bisulfite - SII	3,177	3,618	3,649	3,433	3,348	3,348	3,631	3,768	3,311	3,441	1,778	2,551	39,053
Total Shared FGD System - Disposal Allocation	**119,263**	**150,911**	**151,329**	**128,126**	**129,667**	**129,888**	**156,604**	**155,513**	**128,420**	**131,217**	**105,593**	**118,698**	**1,605,229**
Station II % of Total Site Disposal	38.2%	34.4%	27.3%	37.5%	41.9%	36.9%	33.2%	33.9%	36.0%	36.6%	23.6%	30.1%	
STATION TWO Portion of Disposal	**$ 45,519**	**$ 51,854**	**$ 41,348**	**$ 48,088**	**$ 54,281**	**$ 47,971**	**$ 52,049**	**$ 52,668**	**$ 46,265**	**$ 48,089**	**$ 24,897**	**$ 35,682**	**$ 548,711**
SCR/Scrubber Reagents:													
Ammonia - SII	95,903	109,194	110,146	103,632	101,040	101,054	109,589	120,112	105,544	109,715	56,693	81,329	1,203,952
Emulsified Sulfur - SII (Adjust to $8k/month per HMPL requ	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	96,000
STATION TWO SCR/Scrubber Reagents	**$ 103,903**	**$ 117,194**	**$ 118,146**	**$ 111,632**	**$ 109,040**	**$ 109,054**	**$ 117,589**	**$ 128,112**	**$ 113,544**	**$ 117,715**	**$ 64,693**	**$ 89,329**	**$1,299,952**
Emission Controls: Air Emission Fees	**22,399**	**22,399**	**22,399**	**22,399**	**22,399**	**22,399**	**22,391**	**23,074**	**23,074**	**23,074**	**23,074**	**23,074**	**272,155**
FGD System Amortization	**31,869**	**31,869**	**31,869**	**31,869**	**31,869**	**31,869**	**31,869**	**28,485**	**28,485**	**28,485**	**28,485**	**28,485**	**365,508**
Total Station Two FGD System Cost	**$ 203,690**	**$ 223,316**	**$ 213,762**	**$ 213,988**	**$ 217,589**	**$ 211,293**	**$ 223,898**	**$ 232,339**	**$ 211,368**	**$ 217,363**	**$141,149**	**$176,570**	**$2,486,326**
BREC FGD System Cost @ 197 MW	**$ 128,612**	**$ 141,004**	**$ 134,972**	**$ 135,114**	**$ 137,388**	**$ 133,412**	**$ 141,371**	**$ 146,701**	**$ 133,460**	**$ 137,245**	**$ 89,123**	**$111,488**	**$1,569,890**
BREC FGD System Cost @ 115 MW	**$ 75,078**	**$ 82,312**	**$ 78,791**	**$ 78,874**	**$ 80,201**	**$ 77,880**	**$ 82,526**	**$ 85,638**	**$ 77,908**	**$ 80,118**	**$ 52,026**	**$ 65,082**	**$ 916,434**
TOTAL FGD SYSTEM & DISPOSAL COST													
TOTAL STATION TWO	**$ 264,483**	**$ 291,466**	**$ 284,021**	**$ 336,500**	**$ 377,707**	**$ 272,839**	**$ 291,065**	**$ 300,660**	**$ 271,641**	**$ 279,603**	**$176,761**	**$224,843**	**$3,371,589**
BREC ALLOCATION	**$ 163,632**	**$ 182,641**	**$ 176,878**	**$ 212,472**	**$ 241,578**	**$ 174,462**	**$ 185,193**	**$ 190,027**	**$ 171,136**	**$ 177,098**	**$104,012**	**$137,499**	**$2,116,628**
HMP&L ALLOCATION	**$ 100,851**	**$ 108,824**	**$ 107,144**	**$ 124,027**	**$ 136,129**	**$ 98,376**	**$ 105,871**	**$ 110,633**	**$ 100,505**	**$ 102,506**	**$ 72,748**	**$ 87,344**	**$1,254,958**

Henderson Station Two
2014 / 2015 Operating Plan
Reagent Costs

	Jun '14	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Jan '15	Feb '15	Mar '15	Apr '15	May '15	FYE 14/15
NET GENERATION (MWH)													
TATION TWO:	188,568	196,666	196,138	187,180	194,837	187,260	192,728	196,127	184,792	194,576	184,793	119,184	2,222,849
REC:	132,577	139,548	135,912	136,175	150,207	144,102	146,566	141,394	128,632	144,705	142,436	79,779	1,622,033
MP&L	55,991	57,118	60,226	51,005	44,630	43,158	46,162	54,733	56,160	49,871	42,357	39,405	600,816
justed per HMP&L's Request	-	-	-	-	-	-	-	-	-	-	-	-	-
MP&L (Projected):	55,991	57,118	60,226	51,005	44,630	43,158	46,162	54,733	56,160	49,871	42,357	39,405	600,816
REEN:	279,623	293,865	294,419	278,570	293,275	283,291	295,104	290,451	265,304	284,974	180,311	274,367	3,313,554
DISPOSAL (TONS)													
TATION TWO:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1514	0.1514	0.2043	0.2177	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	28,551	29,777	40,063	40,744	29,500	28,353	29,181	29,696	27,979	29,461	27,980	18,046	359,331
Bottom Ash - Tons / Gross MWH	0.0098	0.0098	0.0958	0.1177	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	
Bottom Ash - Tons of Disposal	1,845	1,924	18,794	22,022	1,906	1,832	1,885	1,919	1,808	1,904	1,808	1,166	58,813
STATION TWO Gross Tons of Disposal	**30,396**	**31,701**	**58,857**	**62,766**	**31,406**	**30,185**	**31,066**	**31,615**	**29,787**	**31,365**	**29,788**	**19,212**	**418,144**
REC:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1514	0.1514	0.2043	0.2177	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	20,073	21,129	27,761	29,642	22,743	21,818	22,192	21,409	19,476	21,910	21,567	12,080	261,800
Bottom Ash - Tons / Gross MWH	0.0098	0.0098	0.0958	0.1177	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	
Bottom Ash - Tons of Disposal	1,297	1,365	13,023	16,021	1,469	1,410	1,434	1,383	1,259	1,416	1,394	780	42,251
BREC Gross Tons of Disposal	**21,370**	**22,494**	**40,784**	**45,663**	**24,212**	**23,228**	**23,626**	**22,792**	**20,735**	**23,326**	**22,961**	**12,860**	**304,051**
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
EC DISPOSAL COSTS	$ 38,039	$ 40,039	$ 72,596	$ 81,280	$ 43,097	$ 41,346	$ 42,054	$ 40,570	$ 36,908	$ 41,520	$ 40,871	$ 22,891	$ 541,211
MP&L:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1514	0.1514	0.2043	0.2177	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	0.1514	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	8,478	8,648	12,302	11,102	6,757	6,535	6,989	8,287	8,503	7,551	6,413	5,966	97,531
Bottom Ash - Tons / Gross MWH	0.0098	0.0098	0.0958	0.1177	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	
Bottom Ash - Tons of Disposal	548	559	5,771	6,001	437	422	451	536	549	488	414	386	16,562
HMP&L Gross Tons of Disposal	**9,026**	**9,207**	**18,073**	**17,103**	**7,194**	**6,957**	**7,440**	**8,823**	**9,052**	**8,039**	**6,827**	**6,352**	**114,093**
Landfill Pozatec/Ash Disposal - Flyash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill Pozatec/Ash Disposal - Bottom Ash (per ton)	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	$ 1.780	
Landfill (Pozatec/Ash Disposal) - HMPL Only	$ 16,066	$ 16,388	$ 32,170	$ 30,443	$ 12,805	$ 12,383	$ 13,243	$ 15,705	$ 16,113	$ 14,309	$ 12,152	$ 11,307	$ 203,084
Landfill Usage Fee (per ton) - HMPL Only	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	$ 1.077	
Landfill Usage Fee - HMPL Only	$ 9,721	$ 9,916	$ 19,465	$ 18,420	$ 7,748	$ 7,493	$ 8,013	$ 9,502	$ 9,749	$ 8,658	$ 7,353	$ 6,841	$ 122,879
IP&L DISPOSAL COSTS	$ 25,787	$ 26,304	$ 51,635	$ 48,863	$ 20,553	$ 19,876	$ 21,256	$ 25,207	$ 25,862	$ 22,967	$ 19,505	$ 18,148	$ 325,963

Henderson Station Two
2014 / 2015 Operating Plan
Reagent Costs

	Jun '14	Jul '14	Aug '14	Sep '14	Oct '14	Nov '14	Dec '14	Jan '15	Feb '15	Mar '15	Apr '15	May '15	FYE 14/15
			Increased due to Landfill Capping										
REEN:													
Pozatec/Ash Disposal - Flyash - Tons / Gross MWH	0.1950	0.1950	0.1950	0.1950	0.1950	0.1950	0.1950	0.1950	0.1950	0.1950	0.1950	0.1950	
Pozatec/Ash Disposal - Flyash - Tons of Disposal	54,522	57,299	57,407	54,316	57,184	55,237	57,540	56,633	51,730	55,565	35,158	53,497	646,088
Bottom Ash - Tons / Gross MWH	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	0.0158	
Bottom Ash - Tons of Disposal	4,430	4,656	4,664	4,413	4,646	4,488	4,675	4,602	4,203	4,515	2,857	4,347	52,496
GREEN Gross Tons of Disposal	58,952	61,955	62,071	58,729	61,830	59,725	62,215	61,235	55,933	60,080	38,015	57,844	698,584
STATION TWO & GREEN Gross Tons of Disposal	89,348	93,656	120,928	121,495	93,236	89,910	93,281	92,850	85,720	91,445	67,803	77,056	1,116,728
Station II % of Total Site Disposal	34.0%	33.8%	48.7%	51.7%	33.7%	33.6%	33.3%	34.0%	34.7%	34.3%	43.9%	24.9%	
FGD SYSTEM COST													
ared FGD System - Disposal Allocation:													
xation Lime - Green	$ 95,801	$ 100,680	$ 100,870	$ 95,440	$ 100,478	$ 97,057	$ 101,104	$ 101,827	$ 93,010	$ 99,906	$ 63,214	$ 96,188	$ 1,145,574
xation Lime - SII	47,641	49,687	49,554	47,290	49,225	47,311	48,692	50,704	47,774	50,303	47,774	30,812	566,767
sh Pond Dredging - SII	-	-	52,500	52,500	-	-	-	-	-	-	-	-	105,000
odium Bisulfite - Green	4,004	4,208	4,216	3,989	4,199	4,056	4,225	4,159	3,799	4,080	2,582	3,929	47,445
odium Bisulfite - SII	2,700	2,816	2,808	2,680	2,790	2,681	2,760	2,808	2,646	2,786	2,646	1,707	31,828
Total Shared FGD System - Disposal Allocation	150,145	157,391	209,947	201,899	156,692	151,105	156,781	159,498	147,229	157,076	116,216	132,635	1,896,614
Station II % of Total Site Disposal	34.0%	33.8%	48.7%	51.7%	33.7%	33.6%	33.3%	34.0%	34.7%	34.3%	43.9%	24.9%	
STATION TWO Portion of Disposal	$ 51,079	$ 53,274	$ 102,184	$ 104,304	$ 52,781	$ 50,730	$ 52,214	$ 54,308	$ 51,161	$ 53,876	$ 51,057	$ 33,069	$ 710,037
:R/Scrubber Reagents:													
nmonia - SII	$ 71,722	$ 74,802	$ 74,601	$ 71,194	$ 74,106	$ 71,224	$ 73,304	$ 77,543	$ 73,062	$ 76,930	$ 73,062	$ 47,122	$ 858,674
nulsified Sulfur - SII	7,763	8,131	8,121	7,762	8,060	7,728	8,065	8,295	7,514	8,218	7,951	5,449	93,057
STATION TWO SCR/Scrubber Reagents	$ 79,485	$ 82,933	$ 82,722	$ 78,956	$ 82,166	$ 78,953	$ 81,369	$ 85,839	$ 80,576	$ 85,148	$ 81,013	$ 52,571	$ 951,731
Emission Controls: Air Emission Fees	28,274	29,748	29,413	28,743	28,877	29,011	29,279	32,571	32,032	32,494	32,340	30,569	363,351
FGD System Amortization	21,716	21,716	21,716	21,716	21,716	21,716	21,716	18,332	18,332	18,332	18,332	18,332	243,672
tal Station Two FGD System Cost	$ 180,554	$ 187,671	$ 236,035	$ 233,719	$ 185,540	$ 180,410	$ 184,578	$ 191,050	$ 182,101	$ 189,850	$ 182,742	$ 134,541	$ 2,268,791
EC FGD System Cost @ 197 MW	$ 114,004	$ 118,497	$ 149,035	$ 147,573	$ 117,152	$ 113,913	$ 116,544	$ 120,631	$ 114,980	$ 119,873	$ 115,385	$ 84,951	$ 1,432,538
IP&L FGD System Cost @ 115 MW	$ 66,550	$ 69,174	$ 87,000	$ 86,146	$ 68,388	$ 66,497	$ 68,034	$ 70,419	$ 67,121	$ 69,977	$ 67,357	$ 49,590	$ 836,253
TOTAL FGD SYSTEM & DISPOSAL COST													
Total Station Two Reagent Costs	$ 244,380	$ 254,014	$ 360,266	$ 363,862	$ 249,190	$ 241,632	$ 247,888	$ 256,827	$ 244,871	$ 254,337	$ 243,118	$ 175,580	$ 3,135,965
BREC Allocation of Reagent Costs	$ 152,043	$ 158,536	$ 221,631	$ 228,853	$ 160,249	$ 155,259	$ 158,598	$ 161,201	$ 151,888	$ 161,393	$ 156,256	$ 107,842	$ 1,973,749
HMP&L Allocation of Reagent Costs	$ 92,337	$ 95,478	$ 138,635	$ 135,009	$ 88,941	$ 86,373	$ 89,290	$ 95,626	$ 92,983	$ 92,944	$ 86,862	$ 67,738	$ 1,162,216

FY 2018 - Station Two Annual Settlement
BREC / HMPL
Summary

I. Station Two O&M Fund Settlement - FY 2018

		HMPL	BREC
Actual funding of Station Two O&M Fund	(Page 2)	$ 360,949.56	$ 618,322.44
Interest earned on Station Two funds	(Page 3)	50.09	85.79
HMPL's actual Station Two expenses	(Page 4)	(350,495.08)	(600,413.56)
Adjustment for over-payment to HMPL from SII O&M Fund	(Page 4a)	(201,166.96)	-
FY 2018 Settlement - Due From/ (To) Station Two O&M Fund		**$ (190,662.39)**	**$ 17,994.67**

II. BREC/ HMPL Station Two Settlement - FY 2018

	G&A/O&M:			
	HMPL payments to BREC for Station Two G&A/ O&M expenses		(Page 2)	$ (12,141,634.43)
	HMPL deposits to Station Two O&M Fund on behalf of BREC		(Page 2)	(618,322.44)
	HMPL share of BREC's actual Station Two G&A/ O&M expenses		(Page 5)	11,461,176.36
	Actual capital expenditures not yet closed as of end of FY 2018 but applied to FY 2018 Settlement			-
	Agreed upon statement of purchase rejects (FY 2018)		(Page 6)	(43,440.34)
	HMPL share of MISO charges		(Page 8)	275,193.49
(A)	**G&A/O&M Settlement - Due (From)/ To BREC**			**$ (1,067,027.36)**
	Inventory:			
	HMPL payments to BREC for Station Two Inventory		(Page 2)	$ (823,271.53)
	HMPL share of cost of inventory purchased by BREC for Station Two		(Page 5)	283,487.23
(B)	**Inventory Settlement - Due (From)/ To BREC**			**$ (539,784.30)**
	HMPL Share of Proceeds from Sale of Station Two Emission Allowances:			
(C)	**Emission Allowances Settlement - Due (From)/ To BREC**		(Page 5)	**$ (4.87)**
	Other Adjustments:			
	HMPL Share Reid 1 Allocation Adjustments (for Jun-17 through Sep-17)		(Page 9)	(43,106.00)
(D)	**Total Other Adjustments - Due (From)/ To BREC**			**$ (43,106.00)**
	FY 2018 Settlement - Due From/ (To) HMPL	**[(A) + (B) + (C) + (D)]**		**$ (1,649,922.53)**

Station Two Settlement - BREC/ HMPL
For the Period June 1, 2018 through January 31, 2019

BREC/ HMPL Station Two Settlement

	G&A/O&M:			
	HMPL payments to BREC for Station Two G&A/ O&M expenses		$	(7,082,620.09)
	HMPL deposits to Station Two O&M Fund on behalf of BREC			(342,379.03)
	HMPL share of BREC's actual Station Two G&A/ O&M expenses			6,946,150.01
	HMPL share of actual Station Two capital expenditures incurred but not yet closed as of 1/31/2019			26,988.92
	HMPL share of MISO charges			203,636.43
(A)	G&A/O&M Settlement - Due (From)/ To BREC		$	(248,223.76)
	Inventory:			
	HMPL payments to BREC for Station Two Inventory		$	(480,241.72)
	HMPL share of cost of inventory purchased by BREC for Station Two			56,409.06
(B)	Inventory Settlement - Due (From)/ To BREC		$	(423,832.66)
	HMPL Share of Proceeds from Sale of Station Two Emission Allowances:			
(C)	Emission Allowances Settlement - Due (From)/ To BREC		$	-
(D)	Total Other Adjustments - Due (From)/ To BREC		$	-
	Amount Due From/ (To) HMPL	[(A) + (B) + (C) + (D)]	$	(672,056.42)

Sharon Farmer

From: Barbara Moll <bmoll@hmpl.net>
Sent: Tuesday, May 19, 2020 11:43 AM
To: Randall Redding
Cc: Sharon Farmer
Subject: RE: 090H-Journal Entry December 31, 2018

Randall,

Yes, they did use the 125 MW

The total was $3,356,896.71 * (125/312) = $1,344,910.54. They didn't round the ratio, so if you take that into account, it matches exactly.

Barbara Moll, CPA
Chief Financial Officer
Henderson Municipal Power & Light
100 Fifth Street
Henderson, KY 42420
270.826.2726

From: Randall Redding <rredding@kdblaw.com>
Sent: Tuesday, May 19, 2020 11:39 AM
To: Barbara Moll <bmoll@hmpl.net>
Cc: Sharon Farmer <sfarmer@kdblaw.com>
Subject: RE: 090H-Journal Entry December 31, 2018

Barbara we think BREC used the FY 2019 125 split/40% to multiple time the 3,356,896.71.= $1,342,758.68.(HMPL share of severance)
Do we see that number anywhere in the BREC summaries?

H. Randall Redding
KING, DEEP AND BRANAMAN
127 North Main Street
P.O. Box 43
Henderson, KY 42419-0043
(270) 827-1852; FAX: (270) 826-7729
rredding@kdblaw.com

From: Barbara Moll [mailto:bmoll@hmpl.net]
Sent: Tuesday, May 19, 2020 11:18 AM
To: Randall Redding
Cc: Chris Heimgartner; Sharon Farmer; Ken Brooks
Subject: FW: 090H-Journal Entry December 31, 2018

Barbara Moll, CPA

Chief Financial Officer
Henderson Municipal Power & Light
100 Fifth Street
Henderson, KY 42420
270.826.2726

From: Barbara Moll
Sent: Thursday, February 06, 2020 11:00 AM
To: Randall Redding <rredding@kdblaw.com>; Sharon Farmer <sfarmer@kdblaw.com>
Subject: FW: 090H-Journal Entry December 31, 2018

This email contains the responses from Donna Windhaus after Mac asked for more detail for the large expenditure.

Attached is BREC's breakdown of how it was calculated

Barbara Moll, CPA

Chief Financial Officer
Henderson Municipal Power & Light
100 Fifth Street
Henderson, KY 42420
270.826.2726

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From: Windhaus, Donna <Donna.Windhaus@bigrivers.com>
Sent: Tuesday, August 27, 2019 11:59 AM
To: Barbara Moll <bmoll@hmpl.net>
Subject: RE: 090H-Journal Entry December 31, 2018

Barbara,

Attached is the severance cost detail. We estimated there would be 62 employees total severed – this number includes SII plant employees and other support staff. The overhead amounts were calculated using the appropriate rates for employee, employee & spouse, employee & children, etc.

I am on vacation next week, so if Mac needs anything else please let me know as soon as possible.

Donna

From: Barbara Moll [mailto:bmoll@hmpl.net]
Sent: Tuesday, August 27, 2019 9:36 AM
To: Windhaus, Donna <Donna.Windhaus@bigrivers.com>
Subject: RE: 090H-Journal Entry December 31, 2018

Donna,

Mac reviewed the information, and needs more detail on the $3,356,896.71 amount. Is there anything you can share in terms of how this was calculated? Maybe a percentage of employee salary? Of course, you can redact any information you need to in terms of identifying information for the employees, but any detail you can share for this would be helpful since it is such a material amount.

I have checked with Mac, and this detail is the last item we need from BREC to complete the audit, so there shouldn't be any further information requests.

I appreciate your help.

Barbara Moll, CPA

Chief Financial Officer
Henderson Municipal Power & Light
100 Fifth Street
Henderson, KY 42420
270.826.2726

From: Windhaus, Donna <Donna.Windhaus@bigrivers.com>
Sent: Monday, August 26, 2019 4:11 PM
To: Barbara Moll <bmoll@hmpl.net>
Subject: RE: 090H-Journal Entry December 31, 2018

Barbara,

The transactions below were for SII closure severance and professional services and were allocated between HMP&L and BREC on the capacity split of 125MW for HMP&L and 187MW for BREC. The transactions are as follows:

Item	Total SII Amount	123/312 Allocated to HMP&L	187/312 Allocated to BREC
Severance Labor/Labor Overheads	$3,356,896.71	$1,344,910.54	$2,011,986.17

Krieg DeVault Inv. #465712	$ 17,321.57	$ 6,939.73	$ 10,381.84
The Brattle Group Inv. #049294	$ 6,912.01	$ 2,769.24	$ 4,142.77
The Brattle Group Inv. #049696	$ 4,271.33	$ 1,711.27	$ 2,560.06
Wm. M. Mercer, Inc. Inv. #134010023696	$ 12,247.00	$ 4,906.65	$ 7,340.35
Wm. M. Mercer, Inc. Inv. #134010023764	$ 354.00	$ 141.83	$ 212.17
Hogan Lovells US LLP Inv. #22200044376	$ 3,553.20	$ 1,423.56	$ 2,129.64
Sullivan Mountjoy PSC Inv. #142,206	$ 4,993.95	$ 2,000.78	$ 2,993.17
	$3,406,549.77	$1,364,803.60	$2,041,746.17

Let me know if you need additional information.

Donna

From: Barbara Moll [mailto:bmoll@hmpl.net]
Sent: Friday, August 23, 2019 11:28 AM
To: Windhaus, Donna <Donna.Windhaus@bigrivers.com>
Subject: FW: 090H-Journal Entry December 31, 2018

Donna,

Please see Mac Neel's email below. Is this something that you can provide documentation for in order for us to complete our Audit?

If you need anything from HMP&L in order to obtain this information, just let me know.

Thank you,

Barbara Moll, CPA

Chief Financial Officer
Henderson Municipal Power & Light
100 Fifth Street
Henderson, KY 42420
270.826.2726

From: Malcolm Neel <mneel@atacpa.net>
Sent: Friday, August 23, 2019 11:24 AM
To: Barbara Moll <bmoll@hmpl.net>
Subject: 090H-Journal Entry December 31, 2018

Barbara,

Could you please see if you can obtain the supporting documentation as to how this charge was arrived at. This is a material transaction and I need the support for this. Thanks.

Account					Description	Entered: Debit	Entered: Credit
10	0999	14350058	0175	1552	090 - Sta Two-HMP&L	$ 1,344,910.54	

					Share		
10	0999	14350058	0314	1552	090 - Sta Two-HMP&L Share	$ 14,844.58	
10	0999	14350058	0313	1552	090 - Sta Two-HMP&L Share	$ 5,048.48	
							$ -
			1552 Total			$ 1,364,803.60	
10	0999	18220000	0175	1510	090 - Sta Two-HMP&L Share		$ 1,344,910.54
10	0999	18220000	0314	1510	090 - Sta Two-HMP&L Share		$ 14,844.58
10	0999	18220000	0313	1510	090 - Sta Two-HMP&L Share		$ 5,048.48
						$ -	
			1510 Total				$ 1,364,803.60
			Grand Total			$ 1,364,803.60	$ 1,364,803.60

Malcom "Mac" Neel, III, CPA, CFE
Member/Partner
P 270.827.1577
Alexander Thompson Arnold PLLC
www.atacpa.net

Estimated Severance Cost
Station II Plant Closure
12/19/2018

Employees Severed: 62
6 Months of Pay Per Severed Employee
Average Rate of Pay Per Severed Employee $38.78/hr

		Amount
Total Severance Labor Payout	**$**	**2,500,701.30**
Labor Overheads Related to Severance Payout:		
FICA	$	191,303.65
Medical	$	568,428.85
Dental	$	23,006.06
Vision	$	3,570.86
EAP	$	322.40
Retiree Medical	$	69,563.59
Total Overheads	**$**	**856,195.41**
Grand Total Related Severance Cost	**$**	**3,356,896.71**

Severed employees include SII plant employees & related support staff

Station Two Settlement - BREC / HMPL
For the Period June 1, 2018 - January 31, 2019

		PER BREC	PER HMPL	
G&A / O&M:				
	HMPL payments to BREC for Station Two G&A / O&M expenses	$ (7,082,620.09)	$ (7,082,620.09)	
	HMPL deposits to Station Two O&M Fund on behalf of BREC	$ (342,379.03)	$ (342,379.03)	
	HMPL share of BREC's actual Station Two G&A / O&M expenses	$ 6,946,150.01	$ 6,391,290.30	
	HMPL share of actual Station Two capital expenditures incurred but not yet closed as of 1/31/2019	$ 26,988.92	$ 24,833.04	
	HMPL share of MISO charges	$ 203,636.43	$ 203,636.43	Listed Separately in Testimony
(A)	G&A / O&M Settlement - Due (From) / To BREC	$ (248,223.76)	$ (805,239.35)	
Inventory:				
	HMPL payments to BREC for Station Two Inventory	$ (480,241.72)	$ (480,241.72)	
	HMPL share of cost of inventory purchased by BREC for Station Two	$ 56,409.06	$ 51,903.09	
(B)	Inventory Settlement - Due (From) / To BREC	$ (423,832.66)	$ (428,338.63)	
HMPL Share of Proceeds from Sale of Station Two Emission Allowances:				
(C)	Emission Allowances Settlement- Due (From) / To BREC	$ -	$ -	
(D)	Total Other Adjustments - Due (From) / To BREC	$ -	$ -	
	Amount Due (From) / To BREC	$ (672,056.42)	$ (1,233,577.98)	
	Difference from 125 MW to 115 MW Due (From) / To BREC [(A) + (B) + (C) + (D)]	$ (561,521.56)		

Exhibit Moll-4

Detailed Reconciliation - Auxiliary Power (Exhibit Moll-3, Exhibit Smith-4)

		Smith Testimony	Moll Testimony	Difference	
Auxiliary Power					
	Oct-18	$ 21,155	$ 10,334	$ (10,821)	Moll Testimony alsoincludes Adjustment for June 2018 - September 2018 as detailed below
	Nov-18	$ 17,886	$ 16,455	$ (1,431)	
	Dec-18	$ 13,815	$ 12,711	$ (1,104)	
	Jan-19	$ 25,895	$ 25,066	$ (829)	
Total - Auxiliary Power		**$ 78,751**	**$ 64,566**	**$ (14,185)**	

		Per Big Rivers	Per HMPL	Difference
June 2018 - September 2018 Adjustment				
	Jun-18	$ 27,491	$ 25,292	$ (2,199)
	Jul-18	$ 29,260	$ 26,920	$ (2,340)
	Aug-18	$ 21,054	$ 19,371	$ (1,683)
	Sep-18	$ 36,338	$ 33,432	$ (2,906)
	Oct-18	$ 21,155	$ 19,463	$ (1,692)
		$ 135,298	$ 124,478	$ (10,820)

Henderson Municipal Power & Light
BALANCE SHEET
For the One Month Ending June 30, 2020

	THIS YEAR	LAST YEAR
ASSETS		
Cash and Short Term Investments:		
CASH	31,794,347	27,498,451
Total Cash and Short Term Investments	***31,794,347***	***27,498,451***
Other Current Assets:		
A/R - DATA / VOICE	24,167	21,455
A/R - OTHER	531,775	558,292
A/R - CITY	3,086,895	3,955,142
A/R STATION TWO 2011	0	0
A/R STATION TWO 2012 - 2019	2,177,652	2,177,652
A/R - UNBILLED REVENUE	2,726,155	2,839,760
RESERVE FOR BAD DEBT	0	0
A/R - INTEREST	0	0
Total Other Current Assets	***8,546,644***	***9,552,301***
Total Current Assets	***40,340,991***	***37,050,752***
Fixed Assets:		
Property Plant & Equipment:		
PROPERTY PLANT & EQUIPMENT	50,999,443	48,978,060
Total Property Plant & Equipment	***50,999,443***	***48,978,060***
Accumulated Depreciation:		
ACCUM. DEPRECIATION	(37,653,119)	(36,745,495)
Total Accumulated Depreciation	***(37,653,119)***	***(36,745,495)***
Net Fixed Assets	***13,346,324***	***12,232,565***
Other Assets:		
INV - COAL STOCK - STATION TWO	2,149,084	2,149,084
INV - LIME	1,351,135	1,351,135
INV - ELECTRIC SUPPLY PARTS	1,118,273	1,040,287
INV - FIBER	160,538	175,733
PREPAYMENTS	275,208	271,095
DEFERRED OUTFLOW - CERS	2,528,013	2,528,013
ARO - ASH POND - NET OF DEPRECIATION	449,395	449,395
INVEST - STATION TWO OPERATIONS	0	0
INVEST - STATION TWO FGD	0	0
INVEST - STATION TWO SCR	0	0
UNREALIZED GAIN OR LOSS ON INVESTMENTS	89,090	89,090
Total Other Assets	***8,120,735***	***8,053,833***
Total Assets	***$61,808,051***	***$57,337,150***

Item 2) **Please provide a detailed listing of all amounts Henderson claims that it owes Big Rivers as of the date of your response and provide all supporting details, contract provisions, correspondence, workpapers, and other Documents. Provide any Excel files in Excel format with all formulas and links intact.**

Response) Please refer to the Moll Testimony and exhibits and Henderson's response to Item 1. All calculations are based upon figures provided by Big Rivers and all requested documents are in Big Rivers' possession.

Witness) **Barbara Moll**

Item 3) **Please refer to the Direct Testimony of Barbara Moll, page 11, lines 7-10, where Ms. Moll states that "the net amount due from Big Rivers to Henderson to resolve disputed operating expenses is $6,359,736.**

a. **Does this net amount include any amounts for the low chlorine coal shortfall described in the Direct Testimony of Paul G. Smith? If so, describe where in Ms. Moll's calculations those amounts can be found, provide the amounts for the low chlorine coal shortfall included in the calculations, and provide a detailed reconciliation between the amounts included in Ms. Moll's calculations and the amounts for low chlorine coal shortfall in Exhibits Smith-2 and Smith-3, with an explanation of any differences. Provide all supporting details, contract provisions, correspondence, workpapers, and other Documents. Provide any Excel files in Excel format with all formulas and links intact.**

Response) No. The figure referenced on p. 11, lines 7-10 of my testimony pertains solely to disputed operating expenses. The financial exchange and inventory write-off of $3,500,219 that would be required to resolve the parties' dispute concerning the production and sale of unwanted energy are addressed on p. 4, line 15, through p. 6, line 12, of my testimony. The low-chlorine coal shortfall related to unwanted energy is reflected in the calculations contained in the document prepared by Big Rivers and attached to my testimony as Exhibit Moll-2. Henderson's calculation of the low-chlorine coal shortfall for unwanted energy and Henderson's native load is $213,023 and $273,213 respectively, the same figures reflected on Exhibits Smith-2 and Smith-3. See response to Item 4 for a more detailed reconciliation. For the convenience of Big Rivers and concerned, Henderson has prepared the "Overview Summary" consolidating all amounts due and provided supporting documentation attached to Henderson's response to Item 1.

Witness) **Barbara Moll**

Item 4) Please provide a detailed reconciliation, with an explanation of any differences, between Exhibit Moll-2 and Exhibits Smith-2 and Smith-3. Provide all supporting calculations. Provide any Excel files in Excel format with all formulas and links intact.

Response) See "Overview Summary" and other supporting documentation provided in Henderson's Response to Item 1, along with the Moll Testimony and exhibits. The main difference is the methodology used for the unwanted energy. The Smith Testimony reflects Big Rivers' unauthorized use of Henderson's coal and lime to generate unwanted energy from June 2016 through December 2017, but does not credit Henderson with the corresponding revenue for that time period. Exhibit Moll-2, the document Big Rivers prepared, presents the full summary of costs and revenue associated with the generation of unwanted energy. The exhibit also reflects amounts due from Henderson to Big Rivers for reimbursement of costs associated with the generation of Henderson's native load.

Witness) Barbara Moll

Item 5) **Please provide a detailed reconciliation, with an explanation of any differences, between the amounts listed for Auxiliary Power in Exhibit Moll-3 and the amounts listed in Exhibit Smith-4. Provide all supporting calculations. Provide any Excel files in Excel format with all formulas and links intact.**

Response) See documentation attached in response to Item 1. The difference in Auxiliary Power figures is attributable solely to BREC's use of an incorrect capacity reservation in calculating Henderson's share of the expense for fiscal 2018-2019. Henderson reserved 115 MW of capacity from Station Two in accordance with its rights under the Station Two contracts. BREC calculated the relative shares of Auxiliary Power and other expenses on the false premise that Henderson should have reserved 125 MW for Fiscal Year 2018-2019.

Witness) **Barbara Moll**

Item 6) Please provide a list by MISO Tariff schedule of the MISO fees included in the calculation of MISO Fees in Exhibit Moll-3, and a list by MISO Tariff schedule of the MISO fees for which Big Rivers has charged Henderson but that are not included in the calculation of MISO Fees in Exhibit Moll-3. For each MISO Tariff schedule for which Big Rivers has charged Henderson but not included in Ms. Moll's calculation of MISO Fees, please explain why Henderson believes Big Rivers is not entitled to be reimbursed by Henderson for those costs. Provide all supporting details, contract provisions, correspondence, workpapers, and other Documents. Provide any Excel files in Excel format with all formulas and links intact.

Response)

Schedule 17	**$272,801.97**	The Schedule 17 tariff permits transmission providers to recover certain costs from MISO market participants under grandfathered agreements. Henderson was not a market participant and is not responsible for these charges. Additionally, Henderson owned the generation and associated transmission facilities needed to supply its load. Big Rivers' integration into MISO did not affect Henderson's independent ability to supply its load just as it had done prior to the integration. Henderson did not require or benefit from any of the services offered under Schedule 17. Therefore, those costs are not recoverable from Henderson.
Schedule 23	**$753,538.92**	Invoices received from Big Rivers indicate these charges are for network and/or point-to-point transmission service. Henderson did not require network or point-to-point transmission service prior to termination of the Station Two contracts. Henderson owned the point-to-point transmission from Station Two to its load meters. Under the terms of the Station Two contracts, if both Station Two units were offline, Big Rivers was obligated to provide replacement power with Station Two as the delivery point. Additionally, Henderson was not a customer of Big Rivers.

Operation Reserve Costs	**$357,908.62**	These charges are allocated to load for Regulation, Spinning, and Supplemental reserves based on the MISO operating reserves market prices. Henderson does not owe operation reserve charges because Henderson self-supplied these reserves. Each of the Station Two units was capable of meeting Henderson's reserve requirements and Henderson had a contractual right to first call on each unit.
Schedule 24	**$38,512.03**	According to invoices received from Big Rivers, this figure represents costs Big Rivers incurred in performing Local Balancing authority (LBA) services between 2010 and 2016. Big Rivers is entitled to recover these charges pursuant to the Schedule 24 tariff and NERC reliability standards.

The figures contained in this response are derived from monthly invoices Big Rivers prepared and submitted to Henderson. All charges were calculated monthly and based upon Henderson's native load. Henderson communicated its position with respect to MISO fees to Big Rivers in correspondence dated January 4, 2019, a copy of which is attached to this response.

Witness) **Brad Bickett**

January 4, 2019

Mr. Bob Berry
President & CEO
Big Rivers Electric Corp.
201 Third Street
Henderson, Kentucky 42420

RE: Disputed Invoices

Dear Bob,

Henderson Municipal Power & Light (HMPL) is in receipt of your letter dated December 26, 2018, and related attachments.

HMPL's position is that the wanted energy whose ownership was at issue in the Henderson Circuit Court damages claim, and which was addressed in the December 17, 2017, Settlement Agreement, is distinct from that unwanted energy which was at issue in the Kentucky Public Service Commission (PSC) proceeding, and in the action currently pending before the Franklin Circuit Court. Only the former was addressed in the Settlement Agreement.

HMPL's agreement to accept responsibility for the energy at issue in the PSC proceeding and the Franklin Circuit Court appeal is premised upon HMPL's right to receive all revenue associated with that energy, including any energy which was generated during that time period and which happened to be economic. Big Rivers is not entitled to manipulate the sequence of power generation so as to reap the benefit of an occasionally robust market, while avoiding entirely the losses associated with a sustained downturn. Big Rivers was not entitled to purchase energy within HMPL's reserved capacity for $1.50 per MWh during the referenced time frame, and HMPL disputes Big Rivers' proposed payment of $88,191 for energy Big Rivers purports to have purchased. The correct amount due from Big Rivers to HMPL for that energy is $408,000, representing MISO revenue, less Big Rivers' marginal cost of power, as reflected in Big Rivers' filings with the PSC and with the Franklin Circuit Court (this figure would increase to $708,000 under a formula using Henderson's lower marginal cost).

100 FIFTH STREET P.O. BOX 8 HENDERSON, KENTUCKY 42419-0008 (270) 826-2726 FAX (270)826-9650

HMPL also disputes Big Rivers' contention that HMPL is indebted to Big Rivers in the amount of $1,422,761.56 for MISO load and transmission fees predating June 1, 2016. HMPL's review of itemized invoices received from Big Rivers for the time period beginning in December 2010 and ending on May 31, 2016, indicates that the amount for which HMPL is responsible, and which HMPL agrees to pay, is $38,512.03. According to the invoices, this figure represents the costs which were incurred by Big Rivers in performing Local Balancing Authority (LBA) services for HMPL between 2010 and 2016, and which Big Rivers is entitled to recover pursuant to the Schedule 24 MISO tariff, and NERC reliability standards. The remaining MISO charges for which Big Rivers invoiced HMPL are inapplicable to HMPL. These charges are as follows: (all calculations are based upon HMPL's native load):

1. $753,538.92. The invoices indicate that these charges are for network and/or point-to-point transmission service. Although the Schedule 23 tariff allows transmission providers to collect charges for those services, HMPL did not require either service and is not responsible for these charges. Further, HMPL is not a customer of Big Rivers.

2. $272,801.97. The Schedule 17 tariff permits transmission providers to recover certain costs from MISO market participants under grandfathered agreements. HMPL was not a market participant during the referenced time period, and is not responsible for these charges.

3. $357,908.62. The invoices indicate that this figure represents operation reserve costs allocated to the HMPL load for regulation, spinning, and supplemental reserves, based upon the MISO operating reserves market prices. However, HMPL did not require operating reserves, and is not responsible for these charges.

Big Rivers' decision to register the Station Two units in MISO was unrelated to any purpose stated in the Station Two contracts, and produced no benefit to HMPL. As stated above, HMPL is agreeable to reimburse Big Rivers for those costs incurred in the performance of LBA services between 2010 and 2016, but is not responsible for the remaining charges invoiced. As a concession, HMPL agrees to forgo reimbursement of overpaid MISO charges for fiscal 2016-2017 and 2017-2018, an action that would increase the amount invoiced for the most recent budget settlement from a current $1,649,922.53 to a projected $1.8 million.

Additionally, HMPL continues to dispute the charges for auxiliary power and for an alleged capacity purchase associated with what Big Rivers contends was an inadequate reservation. HMPL reserved an appropriate amount of capacity in accordance with procedures set forth in the Station Two contracts, and rejects any and all attempts to force an increase in that reservation.

As stated above, HMPL has agreed to accept responsibility for variable costs – and to exercise its corresponding right to receive all revenue - associated with the generation of Excess Henderson Energy between June 1, 2016, and October 31, 2018. Invoices which were prepared by Big Rivers, and which confirm the use of HMPL-owned coal and lime when available to produce the energy at issue, support the calculation reflected on HMPL's recent invoice for MISO revenue in the amount of $2,485,315.06.

Finally, HMPL acknowledges that HMPL owes Big Rivers the sum of $239,300.81 for the month of November 2018, and agrees to remit payment in that amount.

With HMPL's position detailed in this letter and acting as a caveat, and for purposes of settlement discussions only, HMPL extends to BREC a time-sensitive offer to accept payment of $2,307,722.86 in settlement of any and all claims potentially arising from those expenses itemized on the attached Station Two Proposal Sheet. This figure presumes for the sake of argument that HMPL's damages for any wanted energy generated between June 1, 2016, and January 4, 2018, are limited to $88,191. The figure also reflects sums due from HMPL to BREC for MISO fees predating 2016 ($38,512.03), and for a coal shortfall for the month of November 2018 ($239,300.81). If BREC is agreeable to the proposed settlement, please remit payment upon receipt of this letter.

In accordance with the offer outlined above, HMPL rejects Big Rivers' proposed settlement payment of $937,964.03, and returns with this letter your tendered check in that amount.

Sincerely,

Chris Heimgartner

Item 7) **Please provide all workpapers used in the development of Exhibits Moll-2, Moll-3, Moll-4, and Moll-7 in Excel format with all formulas and links intact.**

Response) Please refer to the Moll Testimony and exhibits and Henderson's response to Item 1. All calculations are based upon figures prepared and supplied by Big Rivers and all requested documents are or should be in Big Rivers' possession.

Witness) **Barbara Moll**

Item 8) **Please provide all correspondence related to the final settlement of Fiscal Year 2015-2016 and Fiscal Year 2016-2017.**

Response) The budgets for those years were approved subject to unresolved purchase disputes. As such, there were still open issues to resolve even after the settlement was calculated (see Exhibit Moll-6 and Attachment 1 to Henderson's Response to Item 13(c) of Commission Staff's Initial Request for Information to Henderson). While HMP&L did cash the checks for the Fiscal Year 2015-2016 and Fiscal Year 2016-2017, the parties have previously reconsidered past year Settlements due to subsequently discovered errors despite the fact that the Settlement checks had been cashed. For example, the Fiscal Year 2015-2016 Settlement was adjusted to include previous errors Big Rivers discovered with respect to the budgets for Fiscal Years 2011-2015. Such review and adjustment of prior Settlements has been common practice between the parties, as evidenced by the attached emails reflecting adjustments made by agreement.

Witness) **Barbara Moll**

Randall Redding

From: Castlen, Nicholas R <Nicholas.Castlen@bigrivers.com>
Sent: Wednesday, May 31, 2017 11:22 AM
To: Barbara Moll; Russelburg, Jana N
Cc: Ken Brooks
Subject: RE: SOP Rejects & YE Settlement Amounts- BREC vs. HMPL
Attachments: FY2011-FY2016 Settlement Summary(2017.04.21).xlsx

Barbara,

The attached excel file includes the summary of the annual settlement amounts for all open fiscal years, updated to include FY 2016.

The annual settlement amounts included in the attached file for FY 2011 – FY 2015 agree to the annual settlement amounts provided with my letter dated 2/18/16, with the exception of the following two items:

- FY 2012 adjustment to correct error identified in original FY 2012 annual settlement calculation not previously accounted for (see Note (5) in attached file)
- FY 2015 adjustment to include additional credit of $23.80 for agreed upon SOP rejects based on subsequent discussions with Ken (see Note (6) in attached file)

We can discuss these items, and any questions you may have, during our call at 1:00 this afternoon.

Thanks,

Nick

Nick Castlen, CPA
Manager Finance | Big Rivers Electric Corporation | 201 Third Street, Henderson, KY 42420
Office: (270) 844-6141 | Mobile: (270) 831-0981 | Fax: (270) 844-6408 | Email: nicholas.castlen@bigrivers.com

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From: Castlen, Nicholas R
Sent: Tuesday, May 30, 2017 5:29 PM
To: 'Barbara Moll' <bmoll@hmpl.net>; Russelburg, Jana N <Jana.Russelburg@bigrivers.com>
Cc: Ken Brooks <kbrooks@hmpl.net>
Subject: RE: SOP Rejects & YE Settlement Amounts- BREC vs. HMPL

Barbara,

Thanks for the quick response.

I noticed you were using an outdated version of the FY 2015 Annual Settlement file. I've attached the most recent version of the FY 2011 – FY 2015 Annual Settlement summary, which was originally provided by letter dated 2/18/16.

Please let us know if you have any questions.

Thanks,

Nick

Nick Castlen, CPA
Manager Finance | Big Rivers Electric Corporation | 201 Third Street, Henderson, KY 42420
Office: (270) 844-6141 | Mobile: (270) 831-0981 | Fax: (270) 844-6408 | Email: nicholas.castlen@bigrivers.com

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From: Barbara Moll [mailto:bmoll@hmpl.net]
Sent: Tuesday, May 30, 2017 2:32 PM
To: Russelburg, Jana N <Jana.Russelburg@bigrivers.com>
Cc: Castlen, Nicholas R <Nicholas.Castlen@bigrivers.com>; Ken Brooks <kbrooks@hmpl.net>
Subject: RE: SOP Rejects & YE Settlement Amounts- BREC vs. HMPL

Jana,

Ken Brooks wanted me to get with you regarding the second half of your email. The $652,980 is the total settlement amount for Fiscal Year 2015 (minus anything related to the Statement of Purchase Rejections for that year). This is the total amount that is due from BREC to HMP&L. I have attached the Settlement spreadsheet prepared by BREC, which details out this amount. Basically, the breakdown is as follows:

Big Rivers to pay HMP&L:	$652,979.56
HMPL to receive from O&M Checking:	$ 55,058.50
Big Rivers to receive from O&M Checking:	$ 94,317.50

The amounts that are due from the O&M Checking are not included in the numbers sent to BREC, as these amounts will be paid out of the Station Two O&M Checking once the $652,979.56 is received.

Hopefully this gives you everything you need. If you have any other questions, please let me know.

Thank you!

Barbara Moll, CPA
Comptroller
Henderson Municipal Power & Light
100 Fifth Street
Henderson, KY 42420
270.826.2726

From: Russelburg, Jana N [mailto:Jana.Russelburg@bigrivers.com]
Sent: Tuesday, May 30, 2017 12:02 PM
To: Ken Brooks
Cc: Castlen, Nicholas R
Subject: SOP Rejects & YE Settlement Amounts- BREC vs. HMPL
Importance: High

Ken,

We have been given a couple of numbers from HMPL that I have been asked to review. The amount of 'Outstanding Statement of Purchase Rejections' and 'Outstanding Fiscal Year End Settlements' differ from my records of the numbers and I am needing to determine where these differences are coming from.

	HMPL #'s
Outstanding Statement of Purchase Rejections	$ 1,453,414

Could you provide me the details and breakdown of where the $1,453,414 number is coming from?
What Fiscal Years Statement of Purchases Rejections does this include?

	HMPL #'s
Outstanding Fiscal Year End Settlements	$ 652,980

Could you provide me the details and breakdown of where the $652,980 number is coming from?
What Fiscal Years does this include?

Thanks!

Jana Russelburg
Cash Management/ Station II Accountant
201 Third Street
Henderson, KY 42419
Office: 270-844-6189
Jana.russelburg@bigrivers.com

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Item 9) **Please provide all correspondence and other Documents related to the vertical expansion wall charges that Henderson paid for Fiscal Year 2015-2016 and Fiscal Year 2016-2017.**

Response) Henderson refers Big Rivers to Big Rivers' records and to documents produced in this proceeding, including but not limited to Henderson's response to Item 13 of the Commission Staff's Initial Request for Information to Henderson.

Witness) **Chris Heimgartner**

Item 10) **Please provide a detailed reconciliation, with any explanation of any differences, between the $672,056 listed in Exhibit Moll-3 for FY 2018-2019 Budget Reconciliation and the $649,850 listed in Exhibit Smith-4 for Fiscal Year 2018-2019 Settlement True-Up. Provide all supporting details, contract provisions, correspondence, workpapers, and other Documents. Provide any Excel files in Excel format with all formulas and links intact.**

Response) Henderson objects to this request on the grounds that it seeks documents as easily accessible to Big Rivers as to Henderson. Without waiving said objection, Henderson refers Big Rivers to the attached Station Two settlement summary for Fiscal Year 2018-2019, which was prepared by Big Rivers and transmitted to Henderson as an attachment to an email from Paul Smith dated March 1, 2019. The summary transmitted to Henderson on that date reflects a payment due from Big Rivers to Henderson in the amount of $672,056.42. Henderson has received no other settlement documents for Fiscal Year 2018-2019 and does not know how Big Rivers arrived at the $649,850 settlement figure contained in Exhibit Smith-4.

Witness) **Barbara Moll**

Sharon Farmer

From:	Smith, Paul <Paul.Smith@bigrivers.com>
Sent:	Friday, March 01, 2019 8:50 AM
To:	Barbara Moll
Cc:	Windhaus, Donna
Subject:	RE: FY 2019 Settlement Calculation
Attachments:	HMPL FY 2019 - Annual Settlement Summary (022819).pdf

Barbara – As you requested, attached is the FY 2019 Station Two summary for activity recorded through January, 2019.

Please feel free to call me if you have any comments or questions.

Thanks,
Paul

From: Barbara Moll <bmoll@hmpl.net>
Sent: Thursday, February 28, 2019 4:29 PM
To: Smith, Paul <Paul.Smith@bigrivers.com>
Cc: Chris Heimgartner <cheimgartner@hmpl.net>; Randall Redding <rredding@kdblaw.com>
Subject: FY 2019 Settlement Calculation

Paul,

At our meeting on Tuesday, you mentioned you would be sending me the FY 2019 Settlement Calculation. Do you know when you will have this available to send? We are needing this information to help us analyze the latest Term Sheet from BREC.

Thank you!

Barbara Moll, CPA
Chief Financial Officer
Henderson Municipal Power & Light
100 Fifth Street
Henderson, KY 42420
270.826.2726

Station Two Settlement - BREC/ HMPL
For the Period June 1, 2018 through January 31, 2019

BREC/ HMPL Station Two Settlement

	G&A/O&M:		
	HMPL payments to BREC for Station Two G&A/ O&M expenses	$	(7,082,620.09)
	HMPL deposits to Station Two O&M Fund on behalf of BREC		(342,379.03)
	HMPL share of BREC's actual Station Two G&A/ O&M expenses		6,946,150.01
	HMPL share of actual Station Two capital expenditures incurred but not yet closed as of 1/31/2019		26,988.92
	HMPL share of MISO charges		203,636.43
(A)	**G&A/O&M Settlement - Due (From)/ To BREC**	**$**	**(248,223.76)**
	Inventory:		
	HMPL payments to BREC for Station Two Inventory	$	(480,241.72)
	HMPL share of cost of inventory purchased by BREC for Station Two		56,409.06
(B)	**Inventory Settlement - Due (From)/ To BREC**	**$**	**(423,832.66)**
	HMPL Share of Proceeds from Sale of Station Two Emission Allowances:		
(C)	**Emission Allowances Settlement - Due (From)/ To BREC**	**$**	**-**
(D)	**Total Other Adjustments - Due (From)/ To BREC**	**$**	**-**
	Amount Due From/ (To) HMPL [(A) + (B) + (C) + (D)]	**$**	**(672,056.42)**

Item 11) Please refer to the Note at the bottom of Exhibit Moll-2, which states that the "summary excludes other costs including, but not limited to, capacity purchases ($203,655.82), transmission charges ($1,422,761.54) and auxiliary power."

a. Explain where in her calculations Ms. Moll accounted for the capacity purchases, transmission charges, and auxiliary power listed in the Note. Provide all supporting details, contract provisions, correspondence, workpapers, and other Documents. Provide any Excel files in Excel format with all formulas and links intact.

b. Provide a list of all other costs excluded from the calculation. Provide all supporting details, contract provisions, correspondence, workpapers, and other Documents. Provide any Excel files in Excel format with all formulas and links intact.

Response) a. Exhibit Moll-2, which contains the referenced Note, is a document Big Rivers prepared. Henderson does not owe Big Rivers for the purported capacity purchases and so no such indebtedness is reflected in Ms. Moll's calculations. The appropriate sums due for transmission charges (see Henderson's Response to Item 6) and auxiliary power charges are reflected on Exhibit Moll-3.

b. To the best of my knowledge, no costs were excluded from the calculations.

Witness) Barbara Moll

Item 12) **Please refer to the Direct Testimony of Barbara Moll, page 10, lines 15-16. Provide all studies, correspondence, and other Documents supporting her contention that $1.78 is reasonable compared to the actual costs that Big Rivers incurred to store Henderson's waste in the Green landfill, and provide all studies, correspondence, and other Documents relating to the cost to transport, dispose of, and maintain Station Two waste in the Green landfill or in any other landfill.**

Response) In a letter dated May 5, 1995 (see Exhibit Moll-5), Big Rivers proposed Henderson pay $1.74 per ton for disposal of Henderson's portion of scrubber sludge waste generated from Station Two. According to the terms of Big Rivers' contract with Charah, this rate was to have remained in place throughout the initial three-year term of the contract. While Henderson has not been able to locate a record of the Henderson Utility Commission having approved any escalation in the rate, Henderson allows that an increase from $1.74 per ton in Fiscal Year 2014-2015 to $1.78 per ton in Fiscal Year 2015-2016 is not unreasonable. Indeed, a review of past operating plans confirms that minor fluctuations in the rate were not uncommon. Henderson's objection is to the dramatic increase from $1.78 in 2014-2015 to $5.61 in 2015-2016 and similarly sharp increases all budgets thereafter and which Big Rivers acknowledges is largely attributable to a vertical expansion of its landfill (see Big Rivers' Response to Item 66 of Henderson's First Request for Information to Big Rivers). For documentation of Henderson's objection to the reasonableness of the rate, see Exhibit Moll-6 and Attachment 1 to Henderson's Response to Item 13(c) of Commission Staff's Initial Request for Information to Henderson, and Attachment 1 to Henderson's response to Item 1 of Big Rivers' Initial Request for Information.

Witness) **Barbara Moll**

Item 13) **Please refer to the Direct Testimony of Barbara Moll, page 10, lines 19-21.**

a. **Did Henderson approve the annual settlement true-up for Fiscal Year 2015-2016 or Fiscal Year 2016-2017?**

b. **Did Henderson receive and cash the settlement true-up payment for Fiscal Year 2015-2016?**

c. **Did Henderson receive and cash the settlement true-up payment for Fiscal Year 2016-2017?**

d. **Has Ms. Moll, Ken Brooks, or anyone else on behalf of Henderson previously acknowledged that Henderson agreed with, accepted, or approved the Station Two settlement true-up for Fiscal year 2015-2016 or Fiscal year 2016-2017? Identify all communications, and provide all communications and other Documents, in which Ms. Moll, Mr. Brooks, or anyone else on behalf of Henderson so acknowledges.**

Response) a. The budgets for those years were approved subject to unresolved purchase disputes. As such, there were still open issues to resolve even after the settlement was calculated (see Exhibit Moll-6 and Attachment 1 to Henderson's Response to Item 13(c) of Commission Staff's Initial Request for Information to Henderson). While HMP&L did cash the checks for the Fiscal Year 2015-2016 and Fiscal Year 2016-2017, the parties have previously reconsidered past year Settlements even though the Settlement checks were cashed due to errors that were found. For example, the Fiscal Year 2015-2016 Settlement was adjusted to include previous errors Big Rivers discovered with respect to Fiscal Years 2011-2015. Such review and adjustment of prior Settlements has been common practice between the parties, as evidenced by the attached emails reflecting adjustments made by agreement.

b. Yes.

c. Yes.

d. Henderson objects to this request on the grounds that it seeks documents as easily accessible to Big Rivers as to Henderson. Without waiving said objection, Henderson refers Big Rivers to the response to Subsection (a) of this request.

Witness) Barbara Moll

Item 14) Please refer to the Direct Testimony of Barbara Moll, page 10, lines 8-11.

a. Acknowledge or deny that Mr. Heimgartner was aware of the landfill expansion activity prior to May 2017.

b. Acknowledge or deny that Mr. Ken Brooks was aware of the landfill expansion activity prior to May 2017.

c. Acknowledge or deny that Mr. Gary Quick was aware of the landfill expansion activity prior to May 2017.

d. Acknowledge or deny that Mr. Wayne Thompson was aware of the landfill expansion prior to May 2017.

Response) a. Henderson does not know and is unable to document the date on which specific administrators became aware of Big Rivers' landfill expansion activity. However, see Attachment 1 to Henderson's Response to Item 13(c) of Commission Staff's Initial Request for Information to Henderson for documentation that Henderson questioned the increased disposal rate later attributed to the landfill expansion as part of the budget review process for Fiscal Year 2015-2016. See also Exhibit Moll-6, which is a letter from Ken Brooks to Big Rivers CFO Lindsay Durbin dated December 27, 2017, and which disputes charges associated with the landfill expansion.

b. See Response to Item 14(a).

c. See Response to Item 14(a).

d, See Response to Item 14(a).

Witness) Barbara Moll

Item 15) **Please refer to the Direct Testimony of Seth W. Brown at page 6, lines 20-22. Mr. Brown states, "Since Station Two and Henderson's load were registered in the MISO Network and Commercial Model, some of these six services and their associated costs may be recoverable from HMP&L."**

a. **List each of the six services and their associated costs that Mr. Brown claims are recoverable from Henderson. For each such service or costs;**

i. **Provide the amount Big Rivers charged Henderson,**

ii. **Provide the amount that is recoverable from Henderson,**

iii. **Provide the amount Henderson has paid Big Rivers, and**

iv. **Explain in detail the basis for the claim that these costs are recoverable from Henderson. Provide all supporting details, contract provisions, correspondence, and other Documents, including Excel files in Excel format with formulas and links intact.**

b. **List each of the six services and their associated costs that Mr. Brown claims are not recoverable from Henderson. For each such service or costs provide the amount Big Rivers [sic] that Big Rivers charged Henderson, and explain in detail why Henderson should not be required to reimburse Big Rivers for costs Big Rivers incurred as a result of Station Two and Henderson's load being registered in the MISO Network. Provide all supporting details, contract provisions, correspondence, and other Documents.**

Response) Henderson objects to this request to the extent the request seeks information which is as readily available to Big Rivers as to Henderson. Without waiving that objection, the portion of my testimony referenced in this request requires clarification as follows to eliminate any confusion: costs associated with some of the six (6) services MISO offers under Schedule 17 would be recoverable from Henderson in circumstances which are not present here. The Schedule 17 tariff permits transmission providers to recover certain transmission costs from MISO market participants. These charges are not recoverable from Henderson for two reasons. First, Henderson was not a market participant. Secondly, Henderson owned the generation and transmission facilities used to supply its load and did not require any of the six listed services to continue doing so after Big Rivers joined MISO. Henderson did not require or benefit from any of the services offered under Schedule 17. For these reasons, MISO is not entitled to recover Schedule 17 costs from Henderson. See also Henderson's response to Item 6 of these requests. Henderson has not paid any Schedule 17 charges and Big Rivers is not entitled to recover any Schedule 17 charges. All other requested information is either provided here or is in the possession of Big Rivers.

Witness) **Seth W. Brown**

Item 16) **Please refer to the Direct Testimony of Seth W. Brown at page 8, line 11. Is it Mr. Brown's contention that GFA 510 and 511 are invalid because they were not listed in the Federal Energy Regulatory Commission's order in Docket No. ER04-691?**

a. **If so, please explain GFA 510's inclusion in Attachment P until Station Two was retired.**

b. **If so, please explain GFA 511's inclusion in Attachment P.**

c. **Please explain how GFA 510 and 511 have been used since 2010.**

d. **Is Henderson currently using GFA 511 to schedule its SEPA allocation?**

Response) Mr. Brown does not offer an opinion concerning the validity of either agreement. Mr. Brown's testimony is that neither GFA 510 nor GFA 511 was listed in the Commission's September 16, 2004, order in Docket No. ER04-691 and thus neither can serve as the basis for recovery of Schedule 23 charges.

a. Not applicable.

b. Not applicable.

c. Henderson was not a party to either GFA 510 or GFA 511 prior to February 1, 2019, and has no information concerning the use of either agreement prior to that date. Since February 1, 2019, Henderson has used GFA 511 in allocating its SEPA capacity and energy.

d. Yes.

Witness) **Seth W. Brown** 16(a) & 16(b)

Brad Bickett 16(c) & 16(d)

Item 17) Please refer to the Direct Testimony of Brad Bickett, page 5, lines 12-13. Mr. Bickett states, "Henderson had no direct interactions with MISO concerning Henderson's load or Station Two and had no agreements with MISO."

a. Did Henderson have any indirect interactions with MISO concerning Henderson's load or Station Two? If so, list each such interaction, identify the person or entity acting on behalf of Henderson in each such interaction, and provide all correspondence and other Documents related to each such interaction.

b. Provide all correspondence between Henderson (and anyone acting on its behalf) and MISO concerning Henderson becoming a member of MISO, Henderson's load, Station Two, MISO fees or charges, or any contingency reserve requirements, resource adequacy requirements, reliability requirements, or planning reserve requirements applicable to Henderson, Henderson's load, or Station Two.

c. Provide all correspondence between Henderson and The Energy Authority or TEA, Inc., concerning Henderson becoming a member of MISO, the registration of Henderson's load or Station Two in MISO, MISO fees or charges, or any contingency reserve requirements, resource adequacy requirements, reliability requirements, or planning reserve requirements applicable to Henderson, Henderson's load, or Station Two.

d. Provide all correspondence between Henderson and Big Rivers concerning Henderson becoming a member of MISO, the registration of Henderson's load or Station Two in MISO, MISO fees or charges, or any contingency reserve requirements, resource adequacy requirements, reliability requirements, or planning reserve requirements applicable to Henderson, Henderson's load, or Station Two.

e. Provide all correspondence to, from, or among Henderson or anyone on its behalf, and all studies, analyses, presentations, and other Documents in the possession or control of Henderson concerning Henderson becoming a member of MISO, the registration of Henderson's load or Station Two in MISO, MISO fees or charges, or any contingency reserve requirements, resource adequacy requirements, reliability requirements, or planning reserve requirements applicable to Henderson, Henderson's load, or Station Two.

Response) a. To the extent the testimony requires clarification, Henderson at no time authorized Big Rivers either directly or indirectly through MISO or any other entity to register either Henderson's load or the Station Two generating assets in MISO in any way other than separately from Big Rivers' load and generating assets. Henderson began the process of becoming a MISO market participant in May 2018 upon receiving notice from Big Rivers that the Station Two contracts had terminated. When considering Big Rivers' application to approve termination of the contracts, the Commission recognized that Henderson needed time to arrange for an alternate power supply and approved Big Rivers' offer to Henderson to continue operating the Station Two units for an additional 13 months after termination of the Station Two contracts (a date that would extend Station Two operations through May 31, 2019). The parties subsequently agreed to cease plant operations effective February 1, 2019. Henderson agreed to early termination and consented to the filing of the appropriate Attachment Y notice with the understanding that the status quo would otherwise remain in place until the closure date. It was not until October 25, 2018, after the deadline for rescinding the Attachment Y notice had passed and MISO's approval of plant retirement became final, that Big Rivers notified Henderson of Big Rivers' intent to expel Henderson from Big Rivers' Local Balancing Authority Area (LBAA) effective February 1, 2019 (see attached copy of letter dated October 28, 2018, and

Henderson's response dated November 2, 2018). At that time, approximately three months before the retirement date, Henderson urgently accelerated its effort to secure the services from a third party. Henderson did not have an agreement with MISO for the Station Two units to offer generation into MISO or to take service from MISO for Henderson load prior to when the plant ceased operation on February 1, 2019.

b. Henderson objects to this request on the grounds that the request is overbroad, without defined time parameters, and unduly burdensome. Henderson further objects to the production of any correspondence exchanged between Henderson and MISO and concerning Henderson's potential membership in MISO following the anticipated closure of Station Two, as such communications are not relevant to this proceeding and are not reasonably calculated to lead to the discovery of admissible evidence. Without waiving its objections, Henderson refers Big Rivers to the correspondence attached as Attachment 1 to this response. Henderson also refers Big Rivers to the correspondence attached as Attachment 1 to Item 1 of the Commission Staff's First Request for Information to Henderson.

c. See response to Item 17(b).

d. Henderson objects to this request on the grounds the requested documents are as readily accessible to Big Rivers as to Henderson. Without waiving the objection, Henderson refers Big Rivers to Attachment 1 to Item 1 of the Commission Staff's First Request for Information to Henderson.

e. Henderson objects to this request on the grounds the request is unintelligible and Henderson is unable to determine with any certainty the nature of the information being sought. The request is also overbroad, without defined time parameters, and unduly burdensome.

Without waiving the objection, Henderson refers Big Rivers to Henderson's response to Item 17(b).

Witness) **Brad Bickett**

1

Gary Quick

om:	Gary Quick
ent:	Thursday, September 23, 2010 12:54 PM
To:	'Cheryl A. Bredenbeck'
Cc:	Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
Subject:	BREC Letter
Attachments:	BREC LTR 9-22.pdf

Good Morning Cheryl:

On May 27 of this year I sent you an email at 5:10pm concerning Henderson Municipal Power and Light's intentions in the event Big Rivers Electric Cooperation became a member of MISO. Henderson has also held several meetings with you, MISO staff, and Big Rivers concerning the various options available to Henderson related to how Henderson could participate in MISO. Our position concerning participation in MISO has not changed since our last communication.

Attached is a letter I received this morning from Mr. Bailey at Big Rivers concerning the Henderson Station Two generation units. Henderson needs to know how MISO is planning to register the Henderson units. As stated in the attached letter, Big Rivers informed us this morning that it will act as the Market Participant on behalf of the City of Henderson, which is not consistent with our position and what we have clearly stated to MISO and Big Rivers.

Before we respond to Big Rivers, we need to know what MISO and Big Rivers have done, if anything, regarding the Henderson Station Two capacity, energy, and Market Participation. As we explained to MISO and Big Rivers, Henderson has always intended to register its annual reserved capacity and the related energy. Furthermore, we also informed MISO and Big Rivers that Henderson was considering two options regarding future Market Participation; first, Henderson would request MISO's approval to become a Market Participant or second, Henderson would retain an existing external Market Participant to represent Henderson.

Please let me know the details of how Big Rivers is requesting to join MISO regarding the registration of Henderson's Station Two units and the Market Participant responsibilities.

In advance, thank you. Gary

BREC LTR 9-22.pdf
(400 KB)

Case No. 2019-00269
Attachment 1 to BREC 1-17
Pages 27

Hi Gary,

I do have a copy of your referenced May 27th e-mail. As you recall at the time of those April to May discussions, Big Rivers was preparing for a September 1 integration (that was later postponed) and the timeline for Market Participants to register assets located in the Balancing Authority was June 15th, two and one-half months before the initial planned Big Rivers integration. The postponed integration date is now December 1 with the corresponding deadline for Market Participants (new and existing) to register assets falling the same two and one-half months before, or September 15. If you look at the materials Midwest ISO provided and reviewed in our visit to your offices back on April 27th, Slide 27 of those materials contains the registration process and due dates for Market Participant registration materials to be submitted.

In order for a Big Rivers Balancing Authority to join the Midwest ISO market all generation and load must be registered by Market Participants. Each Market Participant submits asset registration forms and becomes financially responsible for the assets it registers. As you recognize in your message below, under the Midwest ISO process the only way assets can be registered is by a Market Participant. On September 15 Midwest ISO only received the registration from an existing Market Participant – namely Big Rivers. Your May 27th e-mail confirmed that you were agreeable to Big Rivers registering the City's assets. Therefore, we have processed the Big Rivers September 15th Registration accordingly.

As we discussed back in April, the City of Henderson, as an asset owner, can certainly register once you've met the requirements of a Market Participant or elect to have a different Market Participant register these assets on your behalf in a future modeling cycle. The timing of the registration needs to be compliant with the attached Midwest ISO model deadlines presentation. These deadlines are also posted on our website. We would be happy to assist you in better understanding that Market Participant and asset registration process if you would like.

With regard to specific questions as to how the capacity and energy was registered you would need to contact Mr. Bailey at Big Rivers.

Sincerely,

Cheryl

From: Gary Quick [mailto:gquick@hmpl.net]
Sent: Thursday, September 23, 2010 12:54 PM
To: Cheryl A. Bredenbeck
Cc: Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
Subject: BREC Letter

Good Morning Cheryl:

On May 27 of this year I sent you an email at 5:10pm concerning Henderson Municipal Power and Light's intentions in the event Big Rivers Electric Cooperation became a member of MISO. Henderson has also held several meetings with you, MISO staff, and Big Rivers concerning the various options available to Henderson related to how Henderson could participate in MISO. Our position concerning participation in MISO has not changed since our last communication.

Attached is a letter I received this morning from Mr. Bailey at Big Rivers concerning the Henderson Station Two generation units. Henderson needs to know how MISO is planning to register the Henderson units. As stated in the attached letter, Big Rivers informed us this morning that it will act as the Market Participant on behalf of the

Gary Quick

From: Gary Quick
Sent: Thursday, May 27, 2010 5:10 PM
To: 'Cheryl A. Bredenbeck'
Cc: Wayne Thompson
Subject: RE: Big Rivers to register Henderson Question

Hi Cheryl:

Yes, we talked with Mark Bailey yesterday morning at 8:00 am at the Big Rivers Office Building. We informed Mark and his staff that Henderson was agreeable to Big Rivers registering Henderson's 105 MW (as of June 1) and Big Rivers 207 MW separately rather than merely registering the 312 MW. You will need to visit with Mark, but I did not get the impression the separate registration was a problem for Big Rivers. We also informed Mark and his staff that Henderson was visiting with TEA to represent Henderson in the near future. Does this provide you with the information you need??

Thanks, Gary

From: Cheryl A. Bredenbeck [mailto:cbredenbeck@midwestiso.org]
Sent: Thursday, May 27, 2010 4:31 PM
To: Gary Quick
Cc: Wayne Thompson
Subject: Big Rivers to register Henderson Question

Gary,

Thank you for meeting us again last week. I am writing to ask if you had a chance to leave a message for Mark Bailey of Big Rivers informing them that you are fine with Big Rivers registering Henderson assets for this first modeling registration cycle?

Have a great memorial weekend!

Regards,

Cheryl

Cheryl Bredenbeck
Director, Transmission Services
Midwest ISO

5/20/13 [illegible]

[illegible]

Admin [illegible]

36¢ MWH

Base [illegible]

[illegible]

(Kevin Said)

Midwest ISO
Energizing the Heartland

Ray Beaver
Manager, Customer Accounts
Customer Management

P.O. Box 4202
Carmel, Indiana 46082-4202

www.midwestmarket.org

317.249.5167
317.249.5359 fax
317.416.7243 mobile
rbeaver@midwestiso.org

Midwest Independent Transmission System Operator, Inc.

PSC
Mr. Jeffrey Derouen
Executive Director

Jeff R. Derouen
Executive Director
PO Box 615

211 Sower Blvd.
Frankfort, KY
40602-0615

Midwest ISO
Energizing the Heartland

Cheryl Bredenbeck
Director
Transmission Services

1125 Energy Park Drive
St. Paul, Minnesota 55108

www.midwestmarket.org

651.632.8455
651.632.8417 fax
cbredenbeck@midwestiso.org

Midwest Independent Transmission System Operator, Inc.

Midwest ISO
Energizing the Heartland

Settlement

Kevin A. Vannoy
Director, Market Services
Market Operations

P.O. Box 4202
Carmel, Indiana 46082-4202

www.midwestmarket.org

317.249.5978
317.249.5359 fax
317.460.9921 mobile
kvannoy@midwestiso.org

Midwest Independent Transmission System Operator, Inc.

Gary Quick

From: Brenda Jenkins [BJenkins@midwestiso.org]
Sent: Wednesday, May 05, 2010 12:48 PM
To: Gary Quick
Cc: Cheryl A. Bredenbeck; April Peterson
Subject: Instructions for becoming a Market Participant of the Midwest ISO
Attachments: Online Market Participant Registration User Guide.pdf; NonMP Request for System Access_v 1 3 (3).doc; Locating the Distinguished Name information.doc

Gary,

Attached are some documents to assist you in the process of becoming a Market Participant if you choose.

There are three steps to be completed to start the process. If you already have a DUNNs number, you can skip that step. If you do not have a DUNNs number go to page 14 of the Online User Guide for directions. Next you need to register at TSIN to obtain a NERC Entity Code. Your NERC Entity Code is your unique identifier for all your business transactions with the Midwest ISO. For instructions on obtaining your NERC Entity Code go to page 15 of the Online User guide for a step by step screen shot of the steps. The third step is to obtain your digital certificate, go to page 20 of the Online User Guide for instructions. After obtaining, your DUNNs number, NERC Entity Code and Digital Certificate, please complete the attached Request for System Access form and fax back to 317-249-5361. Once we have the form, we can then set you up for access to the portal at https://markets.midwestiso.org/MISO to start the online application. Please copy and paste your distinguished name from your digital certificate and send to me in an email. To locate your Distinguished Name from your Digital certificate, I have attached a document with instructions.

The individual that completes the Online Market Participant Application in the Portal MUST also be listed on that Application as a General or Authorized Contact. It is also highly recommended that you have more than one individual as a contact. Also be sure to register your company legal name at TSIN that you will be using on your application as our business rule requires they must match.

The deadline for entering into the Midwest ISO energy market for July 1, 2010 is June 1, 2010 if you are not registering assets. For assets, the deadline is June 15th for the September 1, 2010 Commercial Model update.

Also, here is a link to the Commercial Model Timeline (http://www.midwestmarket.org/publish/Document/5d42c1_1165e2e15f2_-7d240a48324a?rev=5)

Please feel free to contact me via email or phone if you have any questions.

Brenda Jenkins
Customer Service Ana
Midwest ISO
701 City Center Drive
Carmel, IN 46032
Phone: 317-249-5235
Fax: 317-249-5361
Regular mail to: PO B
Overnight packages t

Per Sandy Duncan 5/7/10

Answer Y to A & B only. Don't enter any load or generation. This does not make you liable for any filings. Suggest going thru credit portion. Call Brenda Monday. She is more familiar. May have to set a date on going to start handling "your stuff". They won't register your load / generation until you tell them to.

HMP&L
HENDERSON MUNICIPAL POWER & LIGHT

September 30, 2010

Mr. Mark Bailey
Big Rivers Electric Corporation
PO Box 24
Henderson, KY 42419-0024

REF: MISO Registration – Big Rivers
PSC Case No. 2010-00043

Dear Mark:

Thank you for your September 27 email (copy attached) concerning the pending MISO registration for Big Rivers. Since receiving your September 22 letter (copy attached) concerning the MISO registration a couple of events have taken place. Henderson has held discussions with The Energy Authority (TEA) which is located in Jacksonville, Florida, and this past Monday, Henderson and TEA participated in a conference call with representatives of MISO.

Based upon the statements made by MISO representatives during the conference call, it is Henderson's understanding that an officer of Big Rivers has certified to MISO that Big Rivers has the authority or right to register all of the capacity and related energy of Henderson Station Two under Big Rivers' name. Big Rivers has apparently also certified that it has the authority or right to act as the MISO Market Participant for Henderson's annual reserved capacity and related energy. As the asset owner, Henderson is not aware of any existing verbal or written authorizations that allow Big Rivers to register Henderson Station Two, which apparently included Henderson's annual reserved capacity and related energy, with MISO. Also, Henderson has not authorized Big Rivers to act as a MISO Market Participant for Henderson. Henderson is not aware of any existing documents between Henderson and Big Rivers that grant Big Rivers the authority to register Station Two with MISO without the written consent from Henderson. As we explained to Big Rivers and MISO, since our first meeting with you on April 12 concerning the possibility of Big Rivers joining MISO, Henderson has considered becoming a Market Participant or retaining a third party to act as our Market Participant. Henderson has also indicated an interest in registering Station Two with MISO since that was one of the options MISO presented to Henderson.

HMP&L

As the owner of Station Two, Henderson does not agree with or approve the Big Rivers proposed MISO registration filing for Station Two and we do not agree with Big Rivers' proposal to act as Market Participant for Henderson's reserved capacity and related energy. We suggest that Big Rivers and MISO correct the proposed Big Rivers' pending registration filing concerning Henderson's Station Two and Big Rivers' proposed market participation to represent Henderson.

Sincerely,

Gary Quick
General Manager

cc: Mr. Ray Beaver, MISO
Ms. Cheryl Bredenbeck, MISO
Mr. Kevin Vannoy, MISO
Mr. Sam Doaks, Sr., TEA
Mr. Bill Clarke, TEA
Mr. Jeff R. Derouen, PSC
Mr. Wayne Thompson, HMP&L

Attachments:
1) May 27, 2010 email to Cheryl A. Brendenbeck
2) September 22, 2010 Mark Bailey Letter
3) September 23, 2010 email to Cheryl A. Brendenbeck
4) September 24, 2010 & September 27, 2010 emails G. Quick and M. Bailey

Gary Quick

From: Mark Bailey [Mark.Bailey@bigrivers.com]
Sent: Monday, September 27, 2010 3:14 PM
To: Gary Quick
Cc: cbredenbeck@midwestiso.org
Subject: RE: BREC Letter

Hello Gary:

You asked in the following e-mail message of September 24, 2010, how Big Rivers submitted the registration request for the Station Two capacity and related energy. Big Rivers, as Market Participant, has submitted to Midwest ISO registration forms for Station Two Unit 1 (153 MW) and Unit 2 (159 MW). The HMP&L load is registered as a part of Big Rivers' load. This was accomplished on or about September 15, 2010, as required by Midwest ISO to assure integration of Big Rivers into Midwest ISO by December 1, 2010, prior to expiration on December 31, 2010, of Midwest ISO Attachment RR Contingency Reserve service to Big Rivers for all generators operated by it. As I noted in my letter of September 22, 2010, this registration will have no negative impact on Big Rivers' performance of its contractual obligations under its agreements with the City of Henderson regarding Station Two. Please let me know if we may provide you further information.

Mark

From: Gary Quick [mailto:gquick@hmpl.net]
Sent: Friday, September 24, 2010 11:46 AM
To: Mark Bailey
Cc: 'Cheryl A. Bredenbeck'; Wayne Thompson
Subject: FW: BREC Letter

Good Morning Mark:

I plan to respond to your September 22 letter concerning MISO, but after I received your letter I had several questions for MISO. Below is an email from Cheryl and she responded to some of my questions. However, please note her comment below concerning my questions about the registration of Station Two capacity and related energy. Cheryl suggested that I contact you; can you let me know how Big Rivers submitted the registration request for the Station Two capacity and related energy? As we discussed with you and your staff, if HMP&L participates in MISO we will register our annual reserved capacity and related energy. We assume Big Rivers has registered its annual allocated capacity and related energy. We have a meeting today with TEA and I'm sure they will need to have this information as they go forward as HMP&L's Market Participant.

In advance, thanks for your help. Gary

From: Cheryl A. Bredenbeck [mailto:cbredenbeck@midwestiso.org]
Sent: Friday, September 24, 2010 10:22 AM
To: Gary Quick
Cc: Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
Subject: RE: BREC Letter

Hi Gary,

I do have a copy of your referenced May 27th e-mail. As you recall at the time of those April to May discussions, Big Rivers was preparing for a September 1 integration (that was later postponed) and the timeline for Market Participants to register assets located in the Balancing Authority was June 15th, two and one-half months before the initial planned Big Rivers integration. The postponed integration date is now December 1 with the corresponding deadline for Market Participants (new and existing) to register assets falling the same two and one-half months before, or September 15. If you look at the materials Midwest ISO provided and reviewed in our visit to your offices back on April 27th, Slide 27 of those materials contains the registration process and due dates for Market Participant registration materials to be submitted.

In order for a Big Rivers Balancing Authority to join the Midwest ISO market all generation and load must be registered by Market Participants. Each Market Participant submits asset registration forms and becomes financially responsible for the assets it registers. As you recognize in your message below, under the Midwest ISO process the only way assets can be registered is by a Market Participant. On September 15 Midwest ISO only received the registration from an existing Market Participant – namely Big Rivers. Your May 27th e-mail confirmed that you were agreeable to Big Rivers registering the City's assets. Therefore, we have processed the Big Rivers September 15th Registration accordingly.

As we discussed back in April, the City of Henderson, as an asset owner, can certainly register once you've met the requirements of a Market Participant or elect to have a different Market Participant register these assets on your behalf in a future modeling cycle. The timing of the registration needs to be compliant with the attached Midwest ISO model deadlines presentation. These deadlines are also posted on our website. We would be happy to assist you in better understanding that Market Participant and asset registration process if you would like.

With regard to specific questions as to how the capacity and energy was registered you would need to contact Mr. Bailey at Big Rivers.

Sincerely,

Cheryl

From: Gary Quick [mailto:gquick@hmpl.net]
Sent: Thursday, September 23, 2010 12:54 PM
To: Cheryl A. Bredenbeck
Cc: Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
Subject: BREC Letter

Good Morning Cheryl:

On May 27 of this year I sent you an email at 5:10pm concerning Henderson Municipal Power and Light's intentions in the event Big Rivers Electric Cooperation became a member of MISO. Henderson has also held several meetings with you, MISO staff, and Big Rivers concerning the various options available to Henderson related to how Henderson could participate in MISO. Our position concerning participation in MISO has not changed since our last communication.

Attached is a letter I received this morning from Mr. Bailey at Big Rivers concerning the Henderson Station Two generation units. Henderson needs to know how MISO is planning to register the Henderson units. As stated in the attached letter, Big Rivers informed us this morning that it will act as the Market Participant on behalf of the

City of Henderson, which is not consistent with our position and what we have clearly stated to MISO and Big Rivers.

Before we respond to Big Rivers, we need to know what MISO and Big Rivers have done, if anything, regarding the Henderson Station Two capacity, energy, and Market Participation. As we explained to MISO and Big Rivers, Henderson has always intended to register its annual reserved capacity and the related energy. Furthermore, we also informed MISO and Big Rivers that Henderson was considering two options regarding future Market Participation; first, Henderson would request MISO's approval to become a Market Participant or second, Henderson would retain an existing external Market Participant to represent Henderson.

Please let me know the details of how Big Rivers is requesting to join MISO regarding the registration of Henderson's Station Two units and the Market Participant responsibilities.

In advance, thank you. Gary

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

Rec. 9/23/2010 AM
@ [illegible]

September 22, 2010

Mr. Gary Quick
General Manager
Henderson Municipal Power & Light
P. O. Box 8
Henderson, KY 42419-0008

Dear Gary:

As you may know, Big Rivers' hearing before the Public Service Commission in its case seeking authority to transfer functional control of its transmission system to Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") concluded September 15, 2010. In order to implement Big Rivers' scheduled December 1, 2010, integration into the Midwest ISO, Big Rivers submitted Commercial Model data to the Midwest ISO on September 15, 2010, and on September 22, 2010, submitted two required certifications regarding the registration of the Station Two generation asset and the City of Henderson load. Pursuant to those submissions, Big Rivers will act as the Market Participant on behalf of the City of Henderson load and Station Two. This designation will have no impact on Big Rivers' performance of its contractual obligations under its agreements with the City of Henderson regarding Station Two. Please let me know if you have any questions, or if we can provide you further information.

Sincerely yours,

Mark A. Bailey

Mark A. Bailey
President and CEO
Big Rivers Electric Corporation

Gary Quick

From:	Gary Quick
Sent:	Thursday, September 23, 2010 12:54 PM
To:	'Cheryl A. Bredenbeck'
Cc:	Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
Subject:	BREC Letter
Attachments:	BREC LTR 9-22.pdf

Good Morning Cheryl:

On May 27 of this year I sent you an email at 5:10pm concerning Henderson Municipal Power and Light's intentions in the event Big Rivers Electric Cooperation became a member of MISO. Henderson has also held several meetings with you, MISO staff, and Big Rivers concerning the various options available to Henderson related to how Henderson could participate in MISO. Our position concerning participation in MISO has not changed since our last communication.

Attached is a letter I received this morning from Mr. Bailey at Big Rivers concerning the Henderson Station Two generation units. Henderson needs to know how MISO is planning to register the Henderson units. As stated in the attached letter, Big Rivers informed us this morning that it will act as the Market Participant on behalf of the City of Henderson, which is not consistent with our position and what we have clearly stated to MISO and Big Rivers.

Before we respond to Big Rivers, we need to know what MISO and Big Rivers have done, if anything, regarding the Henderson Station Two capacity, energy, and Market Participation. As we explained to MISO and Big Rivers, Henderson has always intended to register its annual reserved capacity and the related energy. Furthermore, we also informed MISO and Big Rivers that Henderson was considering two options regarding future Market Participation; first, Henderson would request MISO's approval to become a Market Participant or second, Henderson would retain an existing external Market Participant to represent Henderson.

Please let me know the details of how Big Rivers is requesting to join MISO regarding the registration of Henderson's Station Two units and the Market Participant responsibilities.

In advance, thank you. Gary

BREC LTR 9-22.pdf
(400 KB)

Gary Quick

From:	Wayne Thompson
Sent:	Thursday, August 28, 2014 10:37 AM
To:	Gary Quick
Subject:	FW: Process for the Sale of HMP&L Excess Energy
Attachments:	Henderson Proposed Offer Strategy (Final 3-8-2013).docx

---

From: Sam H. Doaks [mailto:sdoaks@teainc.org]
Sent: Friday, March 08, 2013 2:58 PM
To: David Calhoun (dcalhoun@wyattfirm.com); Wayne Thompson; Gary Quick
Subject: Process for the Sale of HMP&L Excess Energy

Gary, Wayne and David,

I have attached a bullet list describing the process for taking HMP&L Excess Energy to market. Please review and give me or Pat a call if you have any questions.

Regards.

Sam H. Doaks, Sr. | Client Services Manager
301 West Bay Street, Suite 2600
Jacksonville, Florida 32202
: (904) 360-1301 | m: (904) 233-2637 | f: (904) 665-0207 | e: sdoaks@teainc.org

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Proposed Method Whereby Henderson ("HMPL") Offers Excess Energy to Big Rivers ("BREC")

Scenario 1 – HMPL Prepares to and Received a Firm Offer to Buy Station 2 Excess Energy

- 7:30 AM – HMPL's next scheduling day(s) Load forecast completed by TEA
- 8:30 AM – HMPL provides to TEA the expected Station 2 generation availability for the next scheduling day(s)
- 9:00AM – TEA delivers to HMPL the next scheduling day(s);
  - Hourly forecasted load
  - Hourly forecasted excess generation for Station 2
- 9:00-9:30 AM – HMPL verifies TEA's load forecast & excess generation calculation
- 9:30AM-HMPL instructs BREC to;
  - Must-run Station 2 at levels equal to Henderson's hourly forecasted load
  - Offer forecasted excess energy from Station 2 to the MISO Market at Henderson's actual cost (actual costs will be provided to BREC by Henderson)
- 4:00 PM – After the MISO market clears all day ahead bids, Henderson determines the amount of excess energy, if any, they desire to sell and receives firm bids for purchases.
- 4:15PM – Henderson calls BREC and offers them the opportunity to match the highest firm bid.

  - **BREC Accepts Bid**
    - TEA as a Purchase Selling Entity/Market Participant (" PSE/MP") creates a NERC Tag for the bilateral transaction -BREC.Cole1-BREC.BREC
    - Transaction will be entered into TEA's deal capture system as per their duty as Henderson's PSE/MP
    - Settlement to be handled same as today except HMP&L will submit their bill to BREC for the transaction price

  - **BREC Rejects Bid**
    - Henderson sells excess energy to the third party bidder at the same proposed prices offered to BREC
    - Henderson will direct BREC to enter into a financial schedule with the third party. As per today, BREC will continue to receive the dollars from MISO for the day ahead commitment of Station 2. The financial schedule will notify MISO of the change in financial responsibility between BREC and third party. MISO will send an invoice to BREC including a credit for all excess energy generated at Station 2 and a debit for the scheduled excess energy associated with the financial schedule.

Question; what happens if the unit trips in the real time market?
Answer; BREC buys everything from the real time market and they pass the cost/benefit to Henderson for the amount of megawatts on the financial schedule

<u>Question: What happens, if at 4:00 p.m. Henderson doesn't receive any bids to purchase or they decide not to sell to a third party?</u>

<u>Answer: The energy is committed to the Market on Henderson's instructions, Henderson received the day ahead LMP; BREC should be allowed to match the day ahead LMP.</u>

Gary Quick

From: Gary Quick

Sent: Tuesday, November 30, 2010 8:49 AM

To: 'Sam H. Doaks'

Cc: Wayne Thompson

Subject: Commission Meeting

Good Morning Sam.

Last night the Commission voted and gave me the authority to take whatever steps are necessary related to the Station Two capacity and energy. I will try to call you later today to discuss how we should go forward.

Thanks, Gary

Gary Quick

From: Gary Quick
Sent: Wednesday, March 02, 2011 11:26 AM
To: 'Haynes, Greg'; 'Snell, Virginia'; Randall Redding
Cc: Wayne Thompson
Subject: Scheduling Henderson Energy

Good Morning:

I thought you would have an interest in Big Rivers' response to our initial contact concerning TEA scheduling certain amounts of Henderson's energy. TEA is going to contact Bill Blackburn and we will see how this turns out.

Please recall this discussion is about energy "scheduled and taken" by City and TEA would be scheduling the energy for Henderson.

I will keep you advised as we go forward.

Thank you, Gary

From: Gary Quick
Sent: Wednesday, March 02, 2011 11:16 AM
To: 'Mark Bailey'
Subject: RE: MISO

Good Morning Mark

Thanks for getting back to me. I will ask TEA to contact Bill.

Gary

From: Mark Bailey [mailto:Mark.Bailey@bigrivers.com]
Sent: Wednesday, March 02, 2011 9:15 AM
To: Gary Quick
Cc: Bill Blackburn
Subject: MISO

Hello Gary,

Bill Blackburn will be the Big Rivers' contact for the matters you discuss in the letter you delivered to me on February 16, 2011. Would you please provide the names and contact information of the persons with TEA and Midwest ISO we should contact to better understand your request so we can answer your questions?

Mark

Gary Quick

From: Gary Quick

Sent: Wednesday, February 16, 2011 9:26 AM

To: 'Sam H Doaks'

Subject: FW: Meeting With Big Rivers

Good Morning Sam

Please see the note below that I sent to our attorneys in Louisville a few minutes ago If I hear from Big Rivers I will let you know

Thank you, Gary

From: Gary Quick
Sent: Wednesday, February 16, 2011 9:22 AM
To: 'Haynes, Greg'; Snell, Virginia
Subject: Meeting With Big Rivers

Hi Greg / Virginia:

I just came back from my meeting with Big Rivers concerning the scheduling of the Henderson energy I gave Big Rivers (Mark Bailey and Bill Blackburn) the letter concerning TEA and the scheduling of the energy No reaction from Big Rivers except they will look at the letter and get back to me. No surprises during the meeting

Thanks, Gary

Gary Quick

From: Gary Quick
Sent: Tuesday, November 02. 2010 7:46 AM
To: 'William T. Clarke'
Cc: Wayne Thompson; Sam H. Doaks
Subject: RE: Henderson, Kentucky - Registration with MISO

Good Morning Bill:

Just as a point or question. Would we be registering the "City's load??" I don't think Big Rivers will have a problem with that registration because that is sort of what I think they did when they registered.

We need to register the "City's annual Station Two reserved capacity." If we don't make a clarification, Big Rivers is going to take the position that Henderson can register the City's load, but we (Big Rivers) get the megawatts left over from the City's annual Station Two reserved capacity. You may want to give this some thought because I think using the words "City load" is going to be a big problem. You may want to consider correcting your email to Mark Bailey.

Thanks. Gary

From: William T. Clarke [mailto:wclarke@teainc.org]
Sent: Tuesday, November 02, 2010 7:26 AM
To: Mark Bailey
Cc: Gary Quick; Sam H. Doaks; Tyler Wolford; Laura Mitchum; Sidney Jackson; Brenda Jenkins; rbeaver@midwestiso.org; Cheryl A. Bredenbeck; kvannoy@midwestiso.org; Wayne Thompson
Subject: Henderson, Kentucky - Registration with MISO

Mr. Bailey,

Gary Quick has asked The Energy Authority (TEA) to assist the City in registering their load in the Midwest ISO separately from the Big Rivers load. As we've reviewed the Big Rivers registration, it appears that Big Rivers registered both the Big Rivers load and the City's load into a single commercial pricing node (CPnode) – BREC.BREC – effective December 1. 2010. The City would like to separate the Big Rivers load and the City's load into two separate CPnodes to take effect March 1, 2011. To accomplish this effort, TEA will need to file the appropriate documentation with the Midwest ISO by December 15. 2010.

From TEA's perspective, Laura Mitchum will be taking the lead in filing the paperwork with the Midwest ISO, and Tyler Wolford will be our Project Manager for the transition with the City of Henderson becoming an asset owner under TEA's Market Participant registration. We would appreciate it if you would let me know the appropriately people at Big Rivers that Laura, Tyler, and I should contact and plan to work with to facilitate the filing with the Midwest ISO and the effort to transition the City to TEA's RTO services.

To be clear, the City is not changing anything with respect to the Balancing Authority relationship between HMP&L and Big Rivers or the registration status of Henderson Station Two Generation facilities. The only change in Midwest ISO registration will be for the City's load.

If you have any questions on any of this, please call Gary or me.

Thank you.

Bill Clarke
Executive Director, RTO Market Services

Direct Line: 904-360-1404
Mobile Line: 904-472-8723
wclarke@teainc.org
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From: Gary Quick [mailto:gquick@hmpl.net]
Sent: Friday, October 22, 2010 5:19 PM
To: William T. Clarke; Sam H. Doaks
Cc: 'Mark Bailey'; 'sjackson@midwestiso.org'; 'rbeaver@midwestiso.org'; 'Cheryl A. Bredenbeck'; 'kvannoy@midwestiso.org'; Wayne Thompson
Subject: Henderson Municipal Power & Light - Station Two Generation Facilities

Good Afternoon:

Thank you for taking the time to visit with us. Please accept this email as formal authorization for The Energy Authority to represent Henderson Municipal Power & Light in discussions with the Midwest ISO and the Big Rivers Electric Corporation regarding MISO membership, market participation, and registration of the Henderson Station Two Generation Facilities.

Please note that I have sent copies of this authorization to representatives of the Midwest ISO and the Big Rivers Electric Corporation.

Thank you, Gary

FY 2[illegible] - 2010

HENDERSON STATION TWO

	HMPL Reserved Capacity @ 100 MW	HMPL Actual Available MW Capacity	HMPL Actual MWH Take	HMPL Excess MWH Energy	BREC Allocated Capacity @ 212 MW	BREC Actual Take from Allocated MW Capacity	BREC Take of HMPL Excess MWH Energy	BREC Total Actual MWH Take	Station Two Actual MWH Gen	Station Two MWH Capability
Jun-09	72,000	71,706	52,676	19,030	152,640	138,792	5,055	143,847	196,523	224,640
Jul-09	74,400	74,400	52,589	21,811	157,728	139,470	8,856	148,326	200,915	232,128
Aug-09	74,400	74,400	55,496	18,904	157,728	126,373	5,944	132,317	187,813	232,128
Sep-09	72,000	72,000	48,714	23,286	152,640	139,230	8,571	147,801	196,515	224,640
Oct-09	74,400	74,400	43,384	31,016	157,728	137,455	20,343	157,798	201,182	232,128
Nov-09	72,000	72,000	43,882	28,118	152,640	148,176	20,164	168,340	212,222	224,640
Dec-09	74,400	74,400	50,151	24,249	157,728	154,281	11,127	165,408	215,559	232,128
Jan-10	74,400	74,400	54,618	19,782	157,728	134,634	7,951	142,585	197,203	232,128
Feb-10	67,200	67,200	47,757	19,443	142,464	128,498	9,959	138,457	186,214	209,664
Mar-10	74,400	73,940	48,409	25,531	157,728	116,402	13,146	129,548	177,957	232,128
Apr-10	72,000	72,000	44,751	27,249	152,640	67,226	21,334	88,560	133,311	224,640
May-10	74,400	74,400	48,427	25,973	157,728	117,200	12,217	129,417	177,844	232,128
	876,000	875,246	590,854	284,392	1,857,120	1,547,737	144,667	1,692,404	2,283,258	2,733,120
			(3)			(4)		(5)	(2)	(1)

	Average MWH Market Price for Energy
Jun-09	$ 28.08
Jul-09	25.07
Aug-09	27.26
Sep-09	24.93
Oct-09	28.10
Nov-09	26.94
Dec-09	34.56
Jan-10	39.73
Feb-10	37.20
Mar-10	31.05
Apr-10	29.33
May-10	31.47

Source: See Footnote (6)

Station Two Total Capacity - 312 MW

HMPL Reservation - 100 MW or 32.05%

BREC Allocation - 212 MW or 67.95%

(1) Station Two Capability - 312 MW x 24 Hours a Day x 365 Days of Year = 2,733,120 MWH

(2) 2009/2010 Station Two Generation (2,283,258 MWH) divided by Capability (2,733,120 MWH) = 83.54% Percentage of Total Capability actually Generated

(3) HMPL Actual Take (590,854 MWH) divided by HMPL Reserved Capacity (876,000 MWH) = 67.45% (Percentage HMPL actually received from its Reserved MWH)

(3) HMPL Actual Take (590,854 MWH) divided by Station Two Actual Gen.(2,283,258 MWH) = 25.88% (Percentage of Energy HMPL actually received from Total Gen.; But, HMPL paid for 32.05%)

(4) BREC Actual Take (1,547,737 MWH) from Allocated Capacity divided by BREC Allocated Capacity (1,857,120 MWH) = 83.34% (Percentage BREC actually received from its Allocated MWH)

(5) BREC Actual Total Take = 1,692,404 MWH (includes 144,667 MWH of HMPL Excess Energy)

(5) BREC Actual Total Take (1,692,404 MWH) divided by Station Two Actual Gen. (2,283,258 MWH) = 74.12% (Percentage of Energy BREC actually received from Total Gen.; But BREC only paid for 67.95%)

(6) Source: https://www.midwestiso.org/Library/MarketReports/Pages/MarketReports.aspx (Historical LMP)

GENERAL NOTES

HMPL Reservation Cost per MWH based upon '09-'10 Budget Expense Allocation ($10,138,379) divided by HMPL Capacity Reservation (876,000 MWH) = $11.57 per MWH

HMPL Actual Cost per MWH based upon Actual MWH Take ($10,138,379 divided by 590,854 MWH) = $17.15 per MWH

BREC Allocated Cost per MWH based upon '09-'10 Budget Expense Allocation ($21,563,612) divided by BREC Capacity Allocation (1,857,120 MWH) = $11.61 per MWH

BREC Actual Cost per MWH based upon Actual MWH Take ($21,563,612 divided by 1,692,404 MWH) = $12.74 per MWH (Includes $1.50 MWH paid to HMPL)

FY 2[illegible] - 2012

HENDERSON STATION TWO

	HMPL Reserved Capacity @ 110 MW	HMPL Actual Available MW Capacity	HMPL Actual MWH Take	HMPL Excess MWH Energy	BREC Allocated Capacity @ 202 MW	BREC Actual Take from Allocated MW Capacity	BREC Take of HMPL Excess MWH Energy	BREC Total Actual MWH Take	Station Two Actual MWH Gen	Station Two MWH Capability
Jun-11	79,200	79,038	53,954	25,084	145,440	129,945	5,326	135,271	189,225	224,640
Jul-11	81,840	81,840	64,113	17,727	150,288	134,542	3,175	137,717	201,830	232,128
Aug-11	81,840	81,840	61,568	20,272	150,288	135,726	4,463	140,189	201,757	232,128
Sep-11				-		-		-		
Oct-11				-		-		-		
Nov-11				-		-		-		
Dec-11				-		-		-		
Jan-12				-		-		-		
Feb-12				-		-		-		
Mar-12				-		-		-		
Apr-12				-		-		-		
May-12				-		-		-		
	242,880	242,718	179,635	63,083	446,016	400,213	12,964	413,177	592,812	688,896
			(3)			(4)		(5)	(2)	(1)

	Average MWH Market Price for Energy
Jun-11	$ 31.91
Jul-11	43.58
Aug-11	35.61
Sep-11	
Oct-11	
Nov-11	
Dec-11	
Jan-12	
Feb-12	
Mar-12	
Apr-12	
May-12	

Source: See Footnote (6)

Station Two Total Capacity - 312 MW HMPL Reservation - 110 MW or 35.26% BREC Allocation - 202 MW or 64.74%

(1) Station Two Capability - 312 MW x 24 Hours a Day x 365 Days of Year = 2,733,120 MWH

(2) 2011/2012 Station Two Generation (592,812 MWH) divided by Capability (688,896 MWH) = 86.05% Percentage of Total Capability actually Generated

(3) HMPL Actual Take (179,635 MWH) divided by HMPL Reserved Capacity (242,880 MWH) = 73.96% (Percentage HMPL actually received from its Reserved MWH)

(3) HMPL Actual Take (179,635 MWH) divided by Station Two Actual Gen.(592,812 MWH) = 30.30% (Percentage of Energy HMPL actually received from Total Gen.; But, HMPL paid for 36.26%)

(4) BREC Actual Take (400,213 MWH) from Allocated Capacity divided by BREC Allocated Capacity (446,016MWH) = 89.73% (Percentage BREC actually received from its Allocated MWH)

(5) BREC Actual Total Take = 413,177 MWH (includes 12,964 MWH of HMPL Excess Energy)

(5) BREC Actual Total Take (413,177 MWH) divided by Station Two Actual Gen. (592,812 MWH) = 69.70% (Percentage of Energy BREC actually received from Total Gen.; But BREC only paid for 64.74%)

(6) Source: https://www.midwestiso.org/Library/MarketReports/Pages/MarketReports.aspx (Historical LMP)

GENERAL NOTES

(The Budget Expense Allocation Values Below Are Based Upon 3 Months Or 92 Days)

HMPL Reservation Cost per MWH based upon '11-'12 Budget Expense Allocation ($3,203,184) divided by HMPL Capacity Reservation (242,880 MWH) = $13.19 per MWH

HMPL Actual Cost per MWH based upon Actual MWH Take ($3,203,184 divided by 179,635 MWH) = $17.83 per MWH

BREC Allocated Cost per MWH based upon '11-'12 Budget Expense Allocation ($ 5,876,246) divided by BREC Capacity Allocation (446,016MWH) = $13.17 per MWH

BREC Actual Cost per MWH based upon Actual MWH Take ($5,876,246 divided by 413,177 MWH) = $14.22 per MWH (Includes $1.50 MWH paid to HMPL)

Gary Quick

From: Wayne Thompson
Sent: Thursday, August 28, 2014 2:20 PM
To: Gary Quick
Subject: FW: Accepted: FW: GoToMeeting Invitation - HMP&L - Big Rivers Financial Schedule (1:30 p.m. Central - 2:30 p.m. Eastern Time)
Attachments: LTR FEB 10.pdf

From: Gary Quick
Sent: Tuesday, March 08, 2011 3:26 PM
To: 'Sam H. Doaks'
Cc: Wayne Thompson
Subject: FW: Accepted: FW: GoToMeeting Invitation - HMP&L - Big Rivers Financial Schedule (1:30 p.m. Central - 2:30 p.m. Eastern Time)

Hi Sam:

No surprises here; they seldom go anywhere without their lawyers.

I talked with Wayne to see if he recognized the name of the attorney. Our best guess is this may be the attorney who participated in a phone call a few months ago. I think the call took place between TEA, HMP&L, and Big Rivers. Bill Blackburn was on the call (he was in Florida at the time recovering from a health problem) and the other person representing Big Rivers may have been the attorney shown below. I think it was Bill Clarke who made some comments during that phone call about MISO and the Big Rivers attorney pointed out a problem with some of Bill Clarke's statements. Do you recall participating in that phone call?? At this time, we think the lawyer who participated in the phone call is the same person listed below.

If you have someone on your staff knowledgeable about MISO you may want to see if that person is available to participate in the call tomorrow afternoon. Something tells me the Big Rivers attorney is going to give us one or more reasons (related to MISO) why Henderson can not schedule energy as I proposed in the February 10 letter (copy attached) I gave Mark Bailey during my meeting with him and Bill Blackburn on February 16.

Thank you, Gary

From: Sam H. Doaks [mailto:sdoaks@teainc.org]
Sent: Tuesday, March 08, 2011 12:24 PM
To: Gary Quick
Subject: FW: Accepted: FW: GoToMeeting Invitation - HMP&L - Big Rivers Financial Schedule (1:30 p.m. Central - 2:30 p.m. Eastern Time)

Gary,

I thought the person the Bill Blackburn was going to have on the call tomorrow was a member of Big Rivers' staff; it looks like this is their attorney. On the phone call Bill referred to John as their MISO expert. Do you see the need to have HMP&L's Attorney on the call as well? This could be a part of the "Dragging it out" that you referred to last week, but we can hope that it isn't.

Sam H. Doaks, Sr.

The Energy Authority

01 West Bay Street, Suite 2600

Jacksonville, Florida 32202

(904) 360-1301 Office

(904) 233-2637 Cellular Phone

(904) 665-0207 Fax

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-----Original Appointment-----
From: Lilyestrom, John R. [mailto:john.lilyestrom@hoganlovells.com]
Sent: Tuesday, March 08, 2011 12:52 PM
To: Sam H. Doaks
Subject: Accepted: FW: GoToMeeting Invitation - HMP&L - Big Rivers Financial Schedule (1:30 p.m. Central - 2:30 p.m. Eastern Time)
When: Wednesday, March 09, 2011 2:30 PM-3:30 PM (GMT-05:00) Eastern Time (US & Canada).
Where: Conference Call (Sam's Office in JAX)

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

October 25, 2018

Mr. Chris Heimgartner
General Manager
Henderson Municipal Power & Light
P.O. Box 8
Henderson, KY 42419

VIA HAND-DELIVERY AND CERTIFIED MAIL

Re: Notice of Termination of Agreement for Assignment of Responsibility for Complying with Reliability Standards Between Henderson Municipal Power & Light and Big Rivers Electric Corporation, dated July 16, 2009, as amended

Dear Chris,

As you know, on July 27, 2018, Big Rivers Electric Corporation ("Big Rivers") and Henderson Municipal Power and Light ("HMPL") submitted a completed Attachment Y Notice to MISO for Retirement of HMPL Units 1 and 2 effective February 1, 2019. Because HMPL directed Big Rivers not to exercise its right to rescind the Attachment Y submission in the allotted time period, on October 8, 2018, MISO determined that the decision to retire HMPL Units 1 and 2 was final, and as such, determined that the existing interconnection rights for the generators shall terminate as of February 1, 2019. Because the Station Two contracts have terminated and the interconnection rights for the HMPL units will be terminated as of February 1, 2019, Big Rivers is hereby providing HMPL with notice of its intent to terminate the Agreement for Assignment of Responsibility for Complying with Reliability Standards between Henderson Municipal Power & Light and Big Rivers Electric Corporation pursuant to Section 2.3, Termination, of said Agreement. This termination will be effective February 1, 2019.

As a result of the terminations of the Station Two Contracts and the aforementioned agreement (along with the fact that MISO has determined through the Attachment Y process that the Station Two units will be retired as of February 1, 2019), Big Rivers will have no further contractual obligation and will cease providing Local Balancing Authority (LBA), Market Participant (MP) or Meter Data Management Agent (MDMA) services to HMPL as of that date.

As we discussed during our meeting on Friday, October 19, 2018 in your offices, as of February 1, 2019, HMPL will be directly responsible for purchasing energy and capacity to cover HMPL's load. We also discussed the need for HMPL to take the necessary steps prior to February 1, 2019 which will allow HMPL to participate in the MISO market independently from Big Rivers, including but not limited to determining who will act as HMPL's Market Participant/Billing Agent within MISO as well as who will serve as HMPL's LBA and MDMA after Big Rivers ceases to perform these functions. In addition, HMPL will need to submit a Transmission Service Request for Network Integrated Transmission Service (TSR for NITS). It is my understanding from our meeting that HMPL is aware of the steps it needs to take and has been working directly with MISO to accomplish the necessary steps in order to participate in the MISO market by February 1, 2019. To this end, Big Rivers personnel have been working directly with Brad Bickett on these issues, and will continue to cooperate with HMPL during this process as needed.

Following February 1, 2019, Big Rivers will continue to provide to MISO both real-time and after-the-fact tie line data between Big Rivers and HMPL. That power flow will be reported to MISO via ICCP data and checked out with MISO at the end of each day. Should HMPL fail to make arrangements for LBA services, MP service, and MDMA service, MISO will have the ability and authority to charge HMPL for services it is taking from MISO.

Please let me know if this letter generates any questions or if you need anything further from Big Rivers.

Respectfully,

Robert W. Berry

Robert W. Berry
President and CEO
Big Rivers Electric Corporation

cc: MISO, Carmen Clark

Case No. 2019-00269
Attachment 1 to BREC 1-17(e)
Page 2 of 4

Law Offices of
KING, DEEP AND BRANAMAN

Harry L. Mathison, Jr.
W. Mitchell Deep, Jr.
H. Randall Redding*
Eric A. Shappell
Leslie M. Newman
Jennifer P. Andrews
Sharon W. Farmer
Tara L. Hunter

127 North Main Street - P.O. Box 43
Henderson, Kentucky 42419-0043
Telephone (270) 827-1852
FAX (270) 826-7729

Leo King (1893-1982)
William M. Deep (1920-1990)
William M. Branaman (1925-1996)

*Licensed to practice in Indiana

November 2, 2018

Hon. Laura Chambliss
Hon. Tyson Kamuf
Big Rivers Electric Corp.
201 Third Street
Henderson, KY 42420

Dear Laura & Tyson:

In response to Big Rivers President & CEO Bob Berry's letter dated October 25, 2018, HMPL advises that Big Rivers is without authority to unilaterally cease providing Local Balancing Authority (LBA), Market Participation (MP), and/or Meter Data Management Agent (MDMA) services to HMPL on February 1, 2019. TO do so would violate the purpose of the agreement reached and approved as part of the most recent proceeding before the Kentucky Public Service Commission, which is to maintain the status quo for a sufficient period of time for HMPL to make alternative arrangements to meet the electrical energy needs of the city and its inhabitants.

By agreement, the terms and operating parameters of the Station Two contracts remain effective until June 1, 2019, at the latest, pending HMPL's procurement of an alternative power source. Until that time, Big Rivers is obligated to continue providing the above referenced services, as well as any other services essential to HMPL's ability to reliably serve its native load, including but not limited to load-forecasting services. TO do otherwise would hinder HMPL's ability to make alternative arrangements within a reasonable time frame, and would contravene the course of dealing in place between the parties for more than 40 years.

HMPL's submission of the Attachment Y Notice to MISO, and its decision not to exercise its right to rescind the submission within the allotted time period, was not to have been construed as a waiver of the agreement for Big Rivers to continue its performance under the Station Two contracts for a period not to extend beyond May 31, 2018. Additionally, contrary to statements made in the October 25, 2018, letter, HMPL has not accepted Big River's assertions that HMPL is under an obligation to begin purchasing energy and capacity from MISO, or to complete other steps in the procurement process, by February 1, 2019.

Further, Big Rivers' attempt to cease providing LBA services to HMPL ignores its obligations as a signatory to the Amended Balancing Authority Agreement with MISO. Specifically, Big Rivers is responsible for compliance to NERC for the subset of NERC Balancing Authority Reliability Standards defined in the Amended Agreement with respect to its Local Balancing Authority Area- which has long included HMPL, which is fully surrounded by Big Rivers. Big

Rivers is compensated for that service pursuant to MISO Schedule 24. The Amended Agreement permits only one LBA within an LBAA, and makes no provision for creation of additional LBAs internal to the MISO footprint, much less by expelling a load from an existing LBAA.

HMPL has engaged in good-faith negotiations with Big Rivers in an attempt to reach agreeable terms for the provision of a short-term power supply, as well as for closure of the Station Two power plant, resolution of pending litigation, and other matters related to retirement and decommissioning. This is so, despite HMPL's position that the power-supply contract was unrelated to the myriad and complex issues involved in plant closure. Presuming that Big Rivers has approached negotiations with the same good-faith intent, then Big Rivers' decision to issue the termination notice contained in its letter defies explanation.

HMPL remains willing to enter into a contract with Big Rivers for the short-term supply of power, under the terms enumerated on the attached cover page of what Big Rivers has identified as the Confidential Indicative Term Sheet. However, HMPL's position is that agreement on the issues set forth in the remaining pages of the term sheet should not be a condition precedent to the execution of a short-term power contract. HMPL remains willing to negotiate the issues related to plant closure and decommissioning independently from that contract.

Sincerely,

H. Randall Redding
Sharon W. Farmer

cc: Carmen Clark
Bruce Froyum

Item 18) **Please explain the alternatives that Henderson believes were available to Big Rivers and Henderson to meet NERC BAL-002 requirements other than joining MISO. Provide all studies, workpapers, and other Documents related to Henderson's analysis of any alternatives. Provide any Excel files in Excel format with formulas and links intact.**

Response) Henderson objects to this request to the extent it implies NERC BAL-002 requirements were applicable to Henderson. Henderson was not obligated to meet the NERC BAL-002 requirements because Henderson was not registered with NERC as a Balancing Authority and did not perform any Balancing Authority functions. Without waiving the objection, Henderson states that Henderson did not perform any studies or compile any workpapers or other documents concerning Big Rivers' alternatives for meeting any NERC requirements applicable to Big Rivers. However, Big Rivers has stated to the Commission in annual reports filed since the Commission approved Big Rivers' application to transfer functional control of its transmission system to MISO that Big Rivers commissioned such a study in 2009. According to Big Rivers, one alternative recognized in the study was for Big Rivers to implement a standalone self-supply plan. This option would have enabled Big Rivers to meet the NERC BAL-002 requirements without the requirement to obtain Henderson's approval.

Witness) **Brad Bickett**

Item 19) **Please refer to the Direct Testimony of Brad Bickett, page 8, line 12. Please provide a copy of the RFP and all Documents associated with the analysis of the RFP responses and selection of Gridforce Energy Management.**

Response) See attached.

Witness) **Brad Bickett**

OPERATING PROTOCOLS

BETWEEN

MISO RELIABILITY COORDINATOR AND

THE TRANSMISSION OPERATORS

October 31ST, 2018

Rev2

Case No. 2019-00269
Attachment 1 to BREC 1-19
Pages 261

Table of Contents

Background

The revised IRO and TOP standards effective 4-1-17 require the conducting of Operational Planning Analysis and Real time Assessment by both the Transmission Operator (TOP) and Reliability Coordinator (RC). In addition, these new standards require the TOP and RC to develop Operating Plans to prevent and mitigate System Operating Limit (SOL) Exceedances and Interconnection Reliability Operating Limit (IROL) Exceedances, and required the RC Operating Plan to be coordinated with the TOP.

NERC Standard revisions to TOP-001 that became effective 7-1-18 requires including the impact of internal and external system's non-BES Facility overload and/or potential tripping influence on BES facility SOL exceedances and RC determination of IROL's (IRO-002) as determined necessary by the entities.

MISO developed a white paper on the process for determining non-BES Facilities necessary to monitor for the determination of SOL and IROL exceedances on the BES.

MISO, as the RC, BA and Market Operator have the tools for determining SOL Exceedances including the impact of non-BES Facilities and have the means to direct and coordinate with a TOP or to take/coordinate corrective actions to mitigate such exceedances.

These Operating Protocols allow the TOP to utilize the MISO tools, processes and authority to identify and mitigate SOL Exceedances and are consistent with the contractual obligations MISO has under Module F of the Tariff. The TOP may continue to use their own tools and processes in coordination with the MISO RC.

MISO is required by the ISO Agreement (Transmission Owner Agreement) and Module F of the MISO tariff to provide reliability coordination service to the TOP and to support their NERC compliance obligations.

Note: In regard to the ISO Agreement (Transmission Owner Agreement) and Module F of the MISO tariff,

- ISO Agreement (Transmission Owner Agreement) existed before NERC compliance to provide reliability coordination services and market services to its members.
- Module F of the MISO tariff was created after NERC compliance to provide 7 members in the western portion of the MISO footprint that did not want market services with only with reliability coordination services.
- So, Module F provides an accurate description of the reliability coordination services that MISO should provide all of its members under the ISO Agreement (Transmission Owner Agreement).

Module F

<u>MISO Tariff – Preamble:</u> *The Transmission Provider provides reliability coordination services for the Balancing Authorities and Transmission Operators that are Transmission Owners in accordance with the ISO Agreement, the Balancing Authority Agreement and other applicable tariffs. Pursuant to this Part I of Module F, the Transmission Provider shall provide comparable Reliability Coordination Service to entities that are not Transmission Owners on the terms and conditions set forth.*

Some of the comparable services are

<u>Section 72.3.2</u>

- Provide on-line network modeling using state estimation and real-time contingency analysis in the operating time frame;
- Provide operations engineering services, such as analyses of the Combined Reliability Systems' adequacy and security for day-ahead operations, conducting voltage collapse studies when requested, and support for Operating Guides as needed;

Section 72.3.6

- Monitor the Reliability Coordination Customer's compliance requirements with applicable NERC and Regional Entity standards and support such compliance with data as required.
- For the purposes of mitigating an IROL or SOL violation so as to return the Combined Reliability Systems to a reliable state, the Transmission Provider shall have authority to direct the Reliability Coordination Customer to Redispatch generating facilities interconnected to the Combined Reliability Systems to the same extent that the Reliability Coordination Customer is entitled to redispatch such facilities under its transmission tariff and other applicable agreements;

Section 72.12

- To ensure that the Transmission Provider has the ability to direct the actions described in Section 72.10 of this Tariff, the Reliability Coordination Customer and the Transmission Provider will develop detailed Operating Guides for all existing known Flowgates and any future identified Flowgates that specify the division of reliability-related functions and the procedures for coordinating these functions.

ISO Agreement (Transmission Owner Agreement) and Module F

MISO and TOPs are in agreement that Module F and Transmission Owners Agreement are the agreements requiring the service to be performed and these Operating Protocols are documentation to describe how these services are applied to comply with several IRO and TOP standards that relate to managing SOL Exceedances and IROL Exceedances.

MISO and TOPs will annually review the Operating Protocols and anytime the SOL Exceedance definition is changed. The review will take into account workload impacts, efficiency, and effectiveness of the Operating Protocols.

MISO Rating Utilization in the RC processes

Note: This section will be removed once confirmed to be included in other MISO documents.

MISO utilizes 3 different sets of ratings in the Reliability Coordination processes in conjunction with the operation of the MISO market.

For reliability reasons it is important to have consistent timeframes for the utilization of these ratings. Difference in timeframes may cause delays in activation in congestion management and Operating Plans to prevent or mitigate SOL Exceedances.

MISO's utilization of these ratings is not intended to circumvent the Transmission Owner's authority to develop normal and emergency ratings under the FAC-008 standard. MISO defined utilization is meant to provide guidance to the Transmission Owner and its applicable Transmission Operators in their submission of the normal and emergency rating data based on how MISO will treat the ratings in their operation.

Normal rating (Rate A) - MISO will treat this Facility Rating as a continuous rating. When exceeded in real-time. MISO will initiate congestion management and its coordinated Operating Plan to reduce the real-time flow to less than the normal rating.

Long term emergency rating (Rate B) – MISO will treat this Facility Rating based on the time frame defined by TO. The rating is generally at least a one hour rating. When the Real-time Assessment shows the projected post-contingent flow exceeding Rate B, MISO will initiate congestion management prior to the contingency to reduce the predicted post-contingent flow to less than Rate B. MISO will develop an agreed-to post contingent action plan with the TOP that will mitigate the overload with the timeframe of Rate C, if the contingency were to occur prior to reducing the flow below Rate B. In general, MISO initiates its congestion management process, as outlined in its Congestion Management Procedure, prior to a Real-time Assessment predicting post-contingent flow above Rate B. Rate B ratings are utilized for market binding for predicted post-contingent flow.

Note: Transmission Owner may submit a Rate B rating that can be utilized longer than one hour, but should consider not submitting a Rate B rating less than thirty minutes.

Short term emergency rating (Rate C) – MISO will treat this Facility Rating as a 30 minute rating or the timeframe specified by TO. When the Real-time Assessment shows the projected post-contingent flow exceeding Rate C, MISO will initiate congestion management prior to the contingency to reduce the predicted post-contingent flow to less than Rate B. MISO will develop an agreed-to post contingent action plan with the TOP that will mitigate the overload as soon as possible, if the contingency were to occur prior to reducing the flow below Rate C.

Note: Transmission Owner may submit a Rate C rating that can be utilized longer than 30 minutes, but should consider not submitting a rating less than 30 minutes. TOPs must notify MISO of any Rate C less than 30 minutes.

<u>Recommendation:</u> The Transmission Owners are recommended to consider a separation between Rate A, Rate B and Rate C. A separation will allow actions by MISO congestion management and other control actions to reduce the projected post-contingent flow before reaching a level requiring an SOL Exceedance declaration.

1. Operating Planning Analysis

RC obligation:

- Perform an Operational Planning Analysis[1] that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs.[2]
- Have a coordinated Operating Plan(s) [3] for next-day operations to address potential SOL IROL exceedances identified as a result of its Operational Planning while considering the Operating Plans for the next-day provided by its TOPs and BAs.[4]
- Notify impacted entities identified in its Operating Plan(s) cited as to their role in such plan(s).[5]
- Validate all TOPs have access the Extranet, since Extranet is their primary communication means.

TOP obligation

- Have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs.[6]
- Have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified as a result of its Operational Planning Analysis.[7]
- Notify impacted entities identified in the Operating Plan(s).[8]
- Provide Operating Plan to the RC as to their role in such plan(s).[9]

RC Actions

MISO performs and posts to the Extranet an Operational Planning Analysis that identifies:

- Base-flows above normal rating (Rate A)
- Post-contingent flows above the long term emergency rating (Rate B) rating
- Voltages exceeding then emergency voltage limits for base case
- Voltages less than the emergency low limits for post contingent voltages
- Flows greater than or equal established Stability Limit (IROL and non-IROL)

MISO annotates Operational Planning Analysis with mitigating actions to address potential SOL Exceedances and IROL Exceedances. Mitigating actions include references to standing procedures and operating guides. The standing procedures and operating guides collectively form MISO's Operating Plan for operations and is coordinated in advance with impacted TOPs.

MISO will directly notify TOPs with any potential SOL Exceedances that cannot be alleviate with mitigation actions. All other TOPs are notified via Extranet posting.

MISO performs and posts to the Extranet an Operational Planning Analysis that identifies and post results to Extranet

TOP Actions

[1] Module F
[2] IRO-008-2 R1 (RC perform Operational Planning Analysis ...)
[3] Module F
[4] IRO-008-2 R2 (RC shall have coordinated Operating Plans ...)
[5] IRO-008-2 R3 (RC shall notify impacted entities identified in the Operating Plans ...)
[6] TOP-002-4 R1 (TOP shall have an Operational Planning Analysis ...)
[7] TOP-002-4 R2 (TOP shall have an Operating Plans ...)
[8] TOP-002-4 R3 (TOP shall notify entities identified in the Operating Plans ...)
[9] TOP-002-4 R6 (TOP shall provide its Operating Plans ... to its RC)

TOPs may either conduct their own Operational Planning Analysis or utilize the MISO Next Day Security Assessment as their Operational Planning Analysis.

TOPs utilizing the MISO Next Day Security Assessment should

- Download the assessment and validate study inputs and outputs are reflective of their system.
- Confirm to MISO if the results are not reflective of their operation. The review should include validation of[10]:
  - ✓ Load forecasts
  - ✓ Generation output levels
  - ✓ Interchange
  - ✓ Known Protection Systems and Special Protection System status or degradation
  - ✓ Transmission outages
  - ✓ Generator outages
  - ✓ Facility ratings
  - ✓ Identified phase angle and equipment limitations Outages
  - ✓ Noted flow patterns or predict flows on defined interfaces
  - ✓ Validate any mitigating actions
  - ✓ Past experience
- Assist MISO as requested to communicate roles to impacted entities within their operating area.

TOPs utilizing the MISO Next Day Security Assessment should concur with MISO's Next Day Security Assessment, or propose changes necessary for concurrence.

TOP utilizing their own next day assessment should review and coordinate results with MISO for any differences.

<u>Evidence:</u>

MISO will:

- Post their Next Day Security assessments as their Operational Planning Analysis on the Extranet.
- Provide attestation of their Coordinated Operating Plan upon request

TOP should:

- Either capture the MISO Next Day Security assessments or use their own as the Operational Planning Analysis results.
- Document their analysis of the MISO Next Day Security assessments
- Document the MISO Coordinated Operating Plan if there are identified SOL exceedances

[10] Elements of the Operational Planning Analysis Definition

2. *Real-time Analysis*

RC obligation:

- Determine non-BES Facilities to be monitored[11] in the RTCA process.
- Utilize the RTCA's RAS function to model the identified non-BES Facilities in order to determine any potential SOL Exceedances from non-BES contingency. The identification may result from MISO's Low Voltage study (annual or bi-annual), OPA studies by the RC or TOP, or technically sound analysis.
- Monitor Facilities, the status of Remedial Action Schemes, and non-BES Facilities identified as necessary by the Reliability Coordinator, within its RC Area and neighboring RC Areas to identify any SOL exceedances and to determine any IROL exceedances within its RC Area
- .[12]
- Ensure that a Real-Time Assessment is performed at least once every 30 minutes.[13]
- Notify impacted TOPs and BAs within its RC Area, and other impacted RCs as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.[14]
- Notify impacted TOPs and BAs within its RC Area, and other impacted RCs as indicated in its Operating Plan, when the SOL or IROL) exceedance has been prevented or mitigated.[15]
- Ensure read-only version Citrix available to the TOPs for communication of SOL Exceedance mitigation.[16]

TOP obligation:

- Review the non-BES Facilities identified by MISO to be monitored and provide feedback.
- Monitor Facilities, the status of Remedial Action Schemes, and non-BES Facilities within TOP Area and outside area determined as necessary by the TOP.[17]
- Ensure that a Real-time Assessment is performed at least once every 30 minutes.[18]
- Initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.[19]
- Inform its RC of actions taken to return the System to within limits when a SOL has been exceeded.[20]

<u>RC Actions</u>

MISO utilizes their State Estimator (SE) and Real-Time contingency analysis (RTCA) to perform a Real-time Assessment. Contingency Analysis[3] is ran periodically, but at least once every 30 minutes[4]. RTCA is

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[11] MRO clarification the term "monitor" is not a NERC defined term, the Commission was clear in its intent of "monitoring" in <u>FERC Order No. 817</u>, paragraph 35, "...to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in [real-time contingency analysis] systems.""

[12] IRO-002-5 R5 (RC shall monitor …)

[13] IRO-008-2 R4 (Perform Real-time Assessments every 30 minutes …) and Module F

[14] IRO-008-2 R5 (RC shall notify impacted TOPs and BAs … SOL or IROL exceedance)

[15] IRO-008-2 R6 (RC shall notify impacted TOPs and BAs … SOL or IROL exceedance has been prevented)

[16] IRO-008-2 R6 (RC shall notify impacted TOPs and BAs … SOL or IROL exceedance has been prevented)

[17] TOP-001-4 R10 (TOP shall preform the following for determining …)

[18] TOP-001-4 R13 (TOP shall ensure Real-time Assessment is performed at least every 30 minutes)

[19] TOP-001-4 R14 (TOP shall initiate its Operating Plan to mitigate a SOL exceedance ...)

[20] TOP-001-4 R15 (TOP shall inform its RC of actions taken ...)

designed to run approximately once every two minutes. MISO will communicate to the TOP when RTCA has failed to provide a valid solution for at least 20 minutes.

Note: MISO's communication under IRO-008 standard may satisfy the TOP requirement under TOP- 001-4 R14 to initiate their Operating Plan to mitigate SOL Exceedances.

MISO will perform the following steps based on pre and post contingent conditions. Along with this notification MISO notifies all potentially impacted TOPs by providing the MISO SE and RTCA results for the TOPs system via a read only version of our EMS that accessible via Citrix.

Non-BES overloads that do not create post-contingency BES SOL Exceedances will be the sole responsibility of the TOP, unless functional control of the non-BES Facility has been transferred to MISO.

For non-BES pre or post-contingent overloads that impact the BES; MISO will - mitigate the impact on the BES by the most effective means. Any residual overload of the non-BES will be the responsibility of the TOP, unless functional control of the non-BES Facility has been transferred to MISO.

<u>Pre-contingent conditions</u>

When MISO identifies actual steady state flow on a BES Facility is greater than the Facility's normal rating (Rate A), the steady state voltage on a BES Facility is outside of the normal voltage range or actual flow exceeding established Stability Limit (IROL and non-IROL); MISO will contact the TOP to:

a. Confirm the operating conditions and ratings (both in magnitude and length of time to be applied) with the TOP.
b. Communicate any Congestion Management or operating steps being performed.
c. Develop a coordinated action plan when needed. If the BES SOL/IROL exceedance is the result of a non-BES overload, the action plan will mitigate the BES SOL/IROL exceedance by the most effective means.

When MISO determines actual steady state flow on a BES Facility has been reduced to less than the Facility's normal rating (Rate A), the steady state voltage on a BES Facility is within the normal voltage range or actual flow less than or equal established Stability Limit (IROL and non-IROL), MISO will notify the TOP.

<u>Post-contingent conditions</u>

When MISO identifies projected post contingent flow on a BES Facility greater than the short term emergency rating (Rate C) or projected post contingent voltage on a BES Facility less than emergency low voltage limit, MISO will contact the TOP to:

a. Confirm the operating conditions and ratings (both in magnitude and length of time to be applied) with the TOP.
b. Communicate any Congestion Management or operating steps being performed.
c. If the projected post contingent flow is above the short term emergency rating (Rate C) or the post contingent voltage is below emergency voltage range, MISO and TOP must develop an agreed-to post contingency action plan within 30 minutes. The plan should be implementable in 30 minutes if the contingency occurs. If the BES SOL exceedance is the result of a non-BES overload, the action plan will mitigate the BES SOL exceedance by the most effective means.

For TOPs that have implemented defined actions in the agreed-to post contingent action plan, MISO will directly notify those TOPs when MISO declares the SOL Exceedance prevented and/or mitigated. For other TOPs with no post contingent actions, MISO will notify by providing MISO SE and RTCA results via a read only version of our EMS that is accessible to them via Citrix.

When MISO determines projected post contingent flow on a BES Facility is reduced to within the long term emergency rating (Rate B) or projected post contingent voltage on a BES Facility is within emergency low voltage limit, MISO will notify the TOP.

<u>TOP Actions</u>

TOPs may utilize their SCADA system and may use their own RTCA or MISO's RTCA for Real-time Assessment. If the TOP is relying on MISO to fulfill Real-time Assessment requirements, the TOP should have a process to conduct Real-time Assessment of their system when notified by the RC of the RTCA failure, which can include utilizing their own RTCA if they have one or running offline studies as needed when the system changes.

TOPs that use their RTCA should establish a process when their RTCA fails to be performed in 30 minutes. TOP may utilize MISO Real-time Assessment as a backup in the event TOP losses capability to perform Real-time Assessment.

When TOP identifies or MISO communicates the actual steady state flow on a BES Facility is greater than the Facility's normal rating (Rate A), the steady state voltage on a BES Facility is outside of the normal voltage range or actual flow exceeding established Stability Limit (IROL and non-IROL). TOP to take following actions:

a. Confirm the operating conditions and ratings (both in magnitude and length of time to be applied) with MISO.
b. Develop and implement a coordinated action plan with MISO to mitigate the condition.
c. For non-BES Facilities that impact BES Facilities; retain responsibility for any remaining non-BES Facility overload after the implementation of the action plan to mitigate the BES Facility SOL/IROL exceedance.

When TOP determines or MISO notifies the actual steady state flow on a BES Facility is less than or equal to the Facility's normal rating (Rate A), the steady state voltage on a BES Facility is within the normal voltage range or actual flow is less than or equal to established Stability Limit (IROL and non-IROL). TOP will confirm the operating conditions.

<u>Post-contingent conditions</u>

When TOP determines or MISO communicates the projected post contingent flow on a BES Facility is reduced to within the long term emergency rating (Rate B) or projected post contingent voltage on a BES Facility is within the emergency low voltage limit, TOP to take following actions:

a. Confirm ratings (both in magnitude and length of time to be applied) with MISO.
b. Validate MISO results with any available RTCA results of their own, operating guides or operating studies as available or past experience.
c. Review and determine agreement with MISO's post contingency action plan or alternative steps or reason why agreement cannot be reached.
d. Implement any agreed to pre-contingent action(s) deemed necessary.

When TOP determines or MISO notifies the projected post contingent flow on a BES Facility is reduced to within the long term emergency rating (Rate B) or projected post contingent voltage on a BES Facility within the emergency low voltage limit, TOP will confirm the operating conditions.

<u>Note:</u> MISO may notify the TOP if the projected post contingent flow is above the long term emergency rating (Rate B) to confirm the ratings and operating conditions before initiating congestion management and other control actions. This communication is not required by this standard but is a business practice outlined in MISO Congestion Management procedure. In addition, MISO and the TOP may develop a post contingency action plan if the contingency occurs before the normal congestion management processes is able to return the post contingent flow below the long term emergency rating (Rate B).

RC/TOP Actions

Post event, MISO and the TOP should discuss whether the event met any of the SOL Exceedance criteria set forth in MISO's SOL/IROL Methodology and if so then declare the event a SOL Exceedance.

a. Actual flow is above short term emergency rating (Rate C)
b. Actual flow is above long term emergency rating (Rate B) and not reduced to below Rate A within the time frame associated with Rate C.
c. Actual flow is above normal rating (Rate A) and not reduced to the normal rating within the time frame associated with Rate B.
d. Actual voltage was below Emergency Voltage limit.
e. Actual flow on a stability limit (non-IROL) is not reduced to within the limit in 30 minutes or time frame established by an Operating Plan.
f. Projected post contingent flow was greater than short term emergency rating (Rate C) longer than 30 minutes without an agreed-to post contingency action plan.
g. Projected post contingent voltage was less than emergency low voltage limit longer than 30 minutes without an agreed-to post contingency action plan.

MISO and the TOP to jointly develop an SOL Exceedance report.

Evidence:
MISO will:

- Maintain computer logs showing the timing of the RTCA solution, per the NERC Regional Guidance for 30 minute assessment evidence and provide to TOP upon request.
- Maintain computer alarm logs showing the actual condition exceeding the limits.
- Maintain computer reports showing the RTCA results exceeding the limits.
- Document the post contingency action plans
- Document Mitigation of the SOL Exceedance, including starting conditions, mitigation actions and end time.
- Jointly develop SOL Exceedance report with the TOP

TOP should:

- Use MISO-provided evidence on the MISO RTCA solutions, per the NERC Regional guidance for 30 minute assessment evidence, if using MISO RTCA as primary.
- The evidence provided by MISO and from MISO MCS notifications of SE and RTCA failures and System Status Levels issued per MISO procedures for compliance to TOP-001-R13
- Use their own evidence if they are performing their own Real-time Assessment and relying on MISO for backup functionality only.
- Provide their own evidence of performing their own Real-time Assessment when the MISO RTCA has failed for 30 minutes if TOP is relying on MISO for Real-time Assessment requirement.
- Establish their own evidence of the communication with MISO on the actual condition exceeding the limits.
- Establish their own evidence of the communication with MISO regarding the reasonability of the RTCA results.

- Utilize the post contingency action plans jointly developed with MISO.

3. Operational Reliability Data

RC obligation:

- Maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include:
  - ✓ A list of data and information needed by the RC to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, including non-BES data, as deemed necessary by the Reliability Coordinator.
  - ✓ Provisions for notification of current Protection System and Remedial Action Schemes status or degradation that impacts System reliability.
- Distribute its data specification to entities that have data required by the Reliability Coordinators.

TOP obligation:

- Maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to:
  - ✓ A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, including non-BES data, as deemed necessary by the Transmission Operator.
  - ✓ Provisions for notification of current Protection System and Remedial Action Schemes status or degradation that impacts System reliability.
- Distribute its data specification to entities that have data required by the Reliability Coordinators.

<u>TOP Actions</u>

TOP (Data Spec owner)_to evaluate their data specification for missing reliability data required for Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. For missing data, the TOP may provide a request for the specific data to the data owner and a copy of their data specification. If the data is adequate, the TOP should issue an attestation to the data provider.

TOP (Data Spec receiver)_as recipient of a data specification:

- Acknowledge receipt of this data specification.
- Indicate agreement or disagreement with TOP's default data submission format, security protocols and process for resolving data conflicts. If disagreeing, please add comments to aid further discussion with TOP.
- Supply a contact name, phone number and email address for discussing any concerns or questions regarding TOP's data specification or to resolve any disagreement with TOP's default data submission format, security protocol and/or process for resolving data conflicts..

TOP utilizing their own next day assessment should review and coordinate results with MISO for any differences.

<u>Evidence:</u>

TOP should:

- Maintain dated data specification.

- Maintain evidence of distributing its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.
- Attestation of a sufficient data

4. *Real-time Reliability Monitoring and Analysis Capabilities*

4.1 Addressing Quality Issues of Necessary Real-time Data to perform Real-time Monitoring and Real-time Assessments

RC obligation:

- Develop and implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time Monitoring and Real-time Assessments for the RC Area that includes:[21]
  - Criteria for evaluating the quality of Real-time data
  - Provisions to indicate the quality of Real-time data to the RC
  - Actions to address Real-time data quality issues with entities responsible for providing the data when quality affects Real-time Assessments
- Notify RC's Wide Area entities, by MCS, of data quality issues that impact the ability to perform Real-time Monitoring and Real-time Assessments by issuing System Status Level Alerts
- Document data quality issues that impact the ability to perform Real-time Monitoring and Real-time Assessments in the ROWG Monthly Operations Report

TOP obligation:

- Shall develop and implement an Operating Process or Operating Procedure to address the quality of the Real-time Data necessary to perform its Real-time monitoring and Real-time Assessments the Process or Procedure shall include:[22]
  - Criteria for evaluating the quality of Real-time data
  - Provisions to indicate the quality of Real-time data to the System Operators
  - Actions to address Real-time data quality issues with entities responsible for providing the data when quality affects Real-time Assessments
- Maintain evidence necessary for TOP compliance

RC Actions

MISO will:

- Develop an Operating Process or Operating Procedure to address quality of the Real-time data issues for data that is necessary for MISO perform its Real-time monitoring and Real-time Assessments.
- Develop provisions to indicate the quality of Real-time data to MISO RC operators and TOPs.
- Implement its Operating Process or Operating Procedure to address any quality of the Real-time data issues for data that is necessary for MISO perform its Real-time monitoring and Real-time Assessments.
- Provide TOP access to MISO's Operating Process or Operating Procedure that address Real-time data quality issues.
- MISO provide displays used in monitoring quality of Real-time data used for Real-time Assessments by CITRIX.
- Notify Entities within the MISO RC footprint of data quality issues that impact the ability to perform Real-time Monitoring and Real-time Assessments by System Status Level Alerts using the MCS.

[21] IRO-018-1(i) R1
[22] TOP-010-1(i) R1

- Provide documentation that MISO implemented its Operating Process or Operating Procedure to address the quality of data used for Real-time Assessments in the ROWG Monthly Operations Report.
- Provide Real-time data quality information to the MISO RC and make available to TOPs that use MISO Assessment as their primary Real-time Assessment.

TOP Actions

TOPs will:

- Develop an Operating Process or Operating Procedure to address quality issues of data used for Real-time monitoring and Assessment including data requested by the RC's for their Monitoring and Real-time Assessments. Develop provisions to indicate the quality of Real-time data to the System Operators.
- Implement the TOP's Operating Process or Operating Procedure when data issues are detected
- Notify MISO of data quality issues that might affect MISO's Real-time Assessments. TOPs might use voice communication for ICCP or blocks or RTU failures and Data Quality Codes passed with the ICCP point, as outlined in the SO-P-NOP-00424 MISO Member Data Communication Outages.
- For those TOPs using MISO Real-time Assessment as their process, develop TOP's own process that will be used for overall compliance when notified by MISO of failure of MISO EMS/SE/RTCA.
- Develop documentation on TOP's own Operating Process that specifies criteria for evaluating quality of real-time data and actions to address Real-time data quality issues.
- If MISO identifies data quality issues impacting MISO's Real-Time Assessments, MISO will communicate with affected TOPs. Affected TOPs will coordinate with MISO to address Real-Time data quality issues.

Evidence

MISO will:

- Maintain an Operating Process or Operating Procedure addressing data quality issues that impact the ability to perform Real-time Monitoring and Real-time Assessments
- Provide documentation in the ROWG Monthly Operating Report of data quality issues that impact the ability to perform Real-time Monitoring and Real-time Assessments.
- Maintain records that Operating Processes or Procedures were implemented to address the quality issues that impact the ability to perform Real-Time Monitoring and Real-Time assessments.

TOP should:

- Maintain Operating Process or Operating Procedure in electronic or hard copy format
- For TOPS utilizing MISO assessment tools, maintain a copy of MISO's Operating Process or Operating Procedure in electronic or hard copy format
- Use MISO evidence for IRO-018-1 R1, or its own evidence, or in conjunction with MISO evidence, to confirm that it implemented its Operating Process or Operating Procedure that addresses the quality of the Real-time data. This also includes provisions to indicate the quality of Real-time data to the System Operator and actions taken to address Real-time data quality issues when data quality affects Real-time Assessments. This evidence could include dated operator logs, dated checklist, voice recordings, voice transcripts, or other evidence.

- TOPs using MISO Real-time assessments request evidence that Operating Processes or Operating Procedures to address the quality of data used for Real-time Assessments were implemented. Evidence may include:
    - Dated Operating Logs
    - Dated Checklist
    - Dated Repair Request
    - Voice recordings
    - ROWG Monthly Operations Report

4.2 Addressing Quality of Analysis used in Real-time Assessments

RC obligation:

- Implement an Operating Process or Operating Procedure to address quality of analysis used in Real-time Assessments which includes:[23]
    - Criteria for evaluating the quality of analysis
    - Provisions to indicate the quality of analysis
    - Action to address analysis quality issues affecting Real-time Assessments
- Provide documentation of uses of MISO Process and Procedures for addressing the quality of analysis used in Real-time Assessments in the ROWG Monthly Operations Report

TOP obligation:

- Implement an Operating Process or Procedure to address quality of analysis used in Real-time Assessments which includes:
    - Criteria for evaluating the quality of analysis
    - Provisions to indicate the quality of analysis
    - Action to address analysis quality issues affecting Real-time Assessments[24]
- TOPs using MISO Real-time Assessments should monitor MISO's Real-time Assessment quality information. When Assessment quality is suspect, assist MISO when requested to determine if TOP's data or communications is involved
- For TOPs using MISO Real-time Assessments for their primary Assessment tool, the TOP's Operating Process or Operating Procedure shall include a process for addressing the quality of analysis used in the tool used to back up the MISO process when MISO Real-time Assessment is unavailable.

RC Actions

- Develop an Operating Process or Operating Procedure to address the quality of the analysis used in Real-time Assessments and provide indication of the quality of the analysis to the MISO Staff and to TOPs within the RC footprint. (via Citrix) The Assessment tools may include:
    - State Estimator
    - Real-time Contingency Analysis
- Provide documentation to TOPs on MISO's Operating Process that specifies criteria for evaluating quality of the analysis used in Real-time Assessments.

[23] IRO-018-1(i) R2

[24] TOP-010-1(i) R3

- Provide MISO SE and RTCA displays to TOPs (via Citrix and with capability to be filtered on TOP's Area basis) that indicate the quality of the analysis used in Real-time Assessments, such as:
    - Convergence status of SE and last successful time/date of RTCA execution
    - Solution tolerances for SE and RTCA
    - Ranked SE residuals or ranked Normalized Residuals (difference between measured and estimated values), on (filtered) TOP area basis
    - Largest Bus MW/MVAR mismatches on (filtered) TOP area basis
    - Results of SE Bad Data Detection and Identification algorithm and SE Rejected measurements
    - List of Unsolved (Non-Converged) RTCA contingencies
- Take Actions to address issues affecting quality of the analysis used in Real-time Assessment may include such as:
    - Manually rerunning/initiating Real-time sequence
    - Eliminating bad data from Estimator either automatically by SE algorithm or manually, by User
    - Manually replacing failed data points
    - Checking mismatch and iteration tables to determine area causing non convergence
- Provide above-mentioned Real-time Assessment quality information to the MISO RC and make available to TOPs that use MISO Assessment as their primary Real-time Assessment (via Citrix, MCS, or other means).
- Provide access to MISO's Operating Process or Operating Procedures for addressing the quality of analysis used in Real-time Assessments.
- Provide documentation in the ROWG Monthly Operations Report that MISO implemented its Operating Process or Operating Procedure to address issues affecting the quality of the analysis used in Real-time Assessment.

<u>TOP Actions (Utilizing MISO Real-time Assessments as their primary tool/process)</u>

- Develop an Operating Process or Operating Procedure to address the quality of the analysis used in Real-time Assessments utilizing MISO Real-Time Assessment Tools and provide indication of the quality of the analysis to their System Operators
- Monitor the quality of the MISO analysis used in Real-time Assessments
- If MISO identifies Real-time Assessment quality issues, MISO will communicate with applicable TOPs. Applicable TOPs will coordinate with MISO to address Real-Time Assessment quality issues.

<u>TOP Actions (TOP using their own Real-time Assessments)</u>

- Develop and implement an Operating Process or Operating Procedure for to address the quality of analysis results used for Real-time Assessments. The Assessment tools include such as:
    - State Estimator
    - Real-time Contingency Analysis
- Specify criteria for evaluating the quality of analysis used in its Real-time Assessments. The criteria support the identification of applicable analysis quality issues, may include items such as:
    - Solution tolerances
    - Mismatch with Real-time data
    - Convergences

Evidence

MISO will:

- Maintain an Operating Process or Operating Procedure addressing the quality of analysis used in its Real-time Assessment in electronic or hard copy format.
- Provide documentation that it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessment in the ROWG Monthly Operations Report.

TOP should:

- Maintain TOP's Operating Process or Operating Procedure in electronic or hard copy format
- Maintain a copy of MISO's Operating Process or Operating Procedure in electronic or hard copy format
- Use MISO documentation from the ROWG Monthly Operations Reports, or the TOPs own evidence, to confirm that it implemented its Operating Process or Operating Procedure that addresses the quality of the analysis used in Real-time Assessments.
- TOPs using MISO Real-time assessments request evidence that Operating Processes or Operating Procedures to address the analysis quality issues affecting for Real-time Assessments were implemented. Evidence may include:
    - Dated Operating Logs
    - Dated Checklist
    - Dated Repair Request
    - Voice recordings

Revision History

Document	Revision	Reason for Issue	Revised by:	Issue Date	Effective Date
Operating Protocols of The MISO RC and Entity TOPs for the IRO and TOP Standards	0	Original Document: Approved by ROWG On 3/24/2017	ROWG	3/27/2017	4/1/2017
Minor reviews or original Operating Protocols, and added TOP-010-1 and IRO-018-1 to these Operating Protocols	1	New Standards TOP-010-1 and IRO-018-1 become enforceable on 4-1-18.	ROWG	4/1/2018	TOP-010-1 and IRO-018-1 become effective on 4-1-18. All other protocols become effective on the Issue Date.
MISO RC TOP Operating Protocols	2	Updated Protocol to include Changes to NERC Standards IRO-002-4 and TOP-001-4 to include detail of Low Voltage impact on BES SOL's and IROL's	ROWG	10/31/2018	10/31/2018

Appendix A: SOL Exceedance Definition

There are two different types of SOL exceedances in Real-time.

1. SOL exceedance identified in Real-time monitoring based on actual flows
2. SOL exceedance identified in Real-time Assessment/ Contingency analysis based on projected post contingent flows

<u>Proposed Actual SOL Exceedance definition(s)</u>

A. SOL exceedance identified in real-time monitoring (pre-contingency) based on real time system conditions

- Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.
- Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.
- Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.
- Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.
- Any established Stability Limit (non-IROL) is exceeded for longer than 30 minutes or defined by Operating Plan.

B. SOL exceedance identified in the real-time assessment based on Post Contingent system conditions

- Projected Post Contingent Flow on a BES Facility is greater than short term emergency rating (RATE C) for longer than 30 minutes with no agreed-to Post Contingency Action Plan.

<u>Note</u>: for Projected Post Contingent Flow on a BES Facility is greater than the long term emergency rating (RATE B), MISO will begin market action to reduce the projected post contingent flow to less than the long term emergency rating. While the projected post contingent flow is being reduced, MISO and the TOP may develop an agreed-to specific post-contingency action plan should the contingency occur before the reduction is completed.

If the Projected Post Contingent Flow on a BES Facility is greater than the short term emergency rating (RATE C), MISO and the TOP must develop an agreed-to specific post-contingency action within 30 minutes. The plan should be implementable within 30 minutes if the contingency occurs.

- Projected Post Contingent voltage on a BES Facility is less than emergency low voltage limit for longer than 30 minutes with no agreed-to Post Contingency Action Plan

<u>Proposed Potential SOL Exceedance definition(s) – Operational Planning Analysis</u>
<u>There are two different types of potential SOL Exceedances for Operational Planning Assessment</u>

1. Potential SOL exceedances identified in Operational Planning Assessments based on anticipated (Pre-contingency) flows
2. Potential SOL exceedances identified in Operational Planning Assessments based on potential (post-contingent) flows

The following become an SOL exceedance only if the conditions are not mitigated or TOP enters the next day operations without an operating plan to mitigate the identified exceedances.

A. Potential SOL exceedance identified in the Operating Planning Analysis (OPA) based on anticipated (Pre-contingency) conditions

- OPA identifies the anticipated pre-contingency flow on a BES Facility to be higher than the Normal Rating.
- OPA identifies anticipated pre contingent voltage on a BES Facility is lower than the emergency low voltage limit.
- OPA identifies that pre-contingent system conditions exceed established Stability Limits. An operating plan should be implemented to prevent such exceedances.

B. Potential SOL Exceedance Operational Planning Assessment based on potential (post-contingent) conditions

- OPA identifies potential post contingent flows on a BES Facility higher than the Emergency Rating used in the Planning Assessment.
- OPA identifies the potential (post contingent) voltage on a BES Facility is lower than the emergency low voltage limited.
- OPA identifies that potential post contingent system conditions exceed established Stability Limits.

Appendix B: Applicable Standards

IRO-002-5 Reliability Coordination — Monitoring and Analysis

Requirement 5:
Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes and non-BES Facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Measurement 5: Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES Facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

RSAW Audit Guidance: For all, or a sample of, Facilities, Remedial Action Schemes, and non-BES Facilities identified as necessary by the entity, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, review evidence and determine if the entity monitored them to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its area.

IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments

Requirement 1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Measurement 1: Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

RSAW Audit Guidance: Determine if the RC performs an Operational Planning Analysis, which determines if the planned operations for the next-day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its RC Wide Area.

Requirement 2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

> **Measurement 2:** Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.
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> **RSAW Audit Guidance:** Review a sample of Operating Plans provided by the entity to verify that it has a coordinated plan for next-day operations that addresses potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances.

Requirement 3: Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s).

> **Measurement 3:** Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include but is not limited to dated operator logs, or email records.
>
> **RSAW Audit Guidance:** During the audit period, did the entity, per its OPA and development of its Operating Plan, identify impacted entities within its area? Ensure that during the audit period, the entity, per its next-day analysis and development of its Operating Plan, did notify impacted entities.

Requirement 4: Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

> **Measurement 4:** Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.
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> **RSAW Audit Guidance:** For a sample of, BES events selected by the auditor, review evidence (dates and times in the audit period) and determine if the entity ensured a Real-time Assessment was performed at least once every 30 minutes. Auditors can obtain a population of events for sampling from NERC's, or the Regional Entity's, records of mandatory event reports, other information available at the Regional Entities, or a query of the entity. Auditors are encouraged to monitor compliance during the most critical events on the entity's system occurring during the compliance monitoring period.

Requirement 5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Measurement 5: Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

RSAW Audit Guidance: Review evidence that the entity informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan when the results of a Real-time Assessment indicate actual or expected conditions that of its actual or expected operations that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance. Review a sample of evidence that supports entity's assertion that it informed Transmission Operators and, Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance.

Requirement 6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

Measurement 6: Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

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RSAW Audit Guidance: When the SOL or IROL exceedance has been prevented or mitigated, provide documentation that the entity informed impacted Transmission Operator's and, Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. When the SOL or IROL exceedance has been prevented or mitigated, review sample(s) of Requirement R5 evidence for supporting documentation that the entity notified impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators (if appropriate).

IRO-018-1 (i) Reliability Coordinator Real-time Monitoring and Analysis Capabilities

Requirement 1: Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include:

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments

Measurement 1: Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklist, voice recordings, voice transcripts, or other evidence.

RSAW Audit Guidance 1: Review and verify the entity's Operating Process or Operating Procedure addresses the Real-time data necessary to perform Real-time monitoring and Real-time Assessments. Review and verify the entity's Operating Process or Operating Procedure addresses the quality of the Real-time data necessary to perform Real-time monitoring and Real-time Assessments includes; (Part1.1) Criteria for evaluating the quality of Real-time data; (Part 1.2) Provisions to indicate the quality of Real-time data to the System Operator; and (Part 1.3) Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Verify implementation of the Operating Process or Operating Procedure which addresses the quality of the Real-time data necessary to perform Real-time monitoring and Real-time Assessments.

Requirement 2: Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include:

2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

2.2. Provisions to indicate the quality of analysis used in Real-time Assessments; and

2.3. Actions to address analysis issues affecting its Real-time Assessments.

Measurement 2: Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

RSAW Audit Guidance 2: Review and verify the entity's Operating Process or Operating Procedure addresses the quality of analysis used in its Real-time Assessment includes: (Part 2.1) Criteria for evaluating the quality of analysis used in its Real-time Assessment; (Part 2.2) Provisions to indicate the quality of analysis used in its Real-time Assessments; and (Part 2.3) Actions to address analysis quality issues affecting its Real-time Assessments. Verify implementation of the Operating Process or Operating Procedure which addresses the quality of analysis used in its Real-time Assessments.

TOP-001-4 Transmission Operations

Requirement 10: Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES Facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. 10.5 Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. 10.6 Obtain and utilize status, voltages, and flow data for non-BES Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

Measurement 10: Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, ~~Supervisory Contr~~ol and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

RSAW Audit Guidance: (10.1) Verify the entity monitored Facilities within its Transmission Operator Area for determining SOL exceedances within its Transmission Operator Area.
(10.2) Verify the entity monitored the status of Remedial Action Schemes within its Transmission Operator Area for determining SOL exceedances within its Transmission Operator Area.
(10.3) Verify the entity monitored non-BES Facilities within its Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
(10.4) Verify the entity obtained and utilized status, voltages, and flow data for Facilities outside its Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
(10.5) Verify the entity obtained and utilized the status of Remedial Action Schemes outside its Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
(10.6) Verify the entity obtained and utilized status, voltages, and flow data for non-BES Facilities outside its Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.

Requirement 13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Requirement 14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Measurement 14: Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

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RSAW Audit Guidance: Did the entity have any SOL exceedances during the compliance monitoring period? Yes / No. If Yes, provide a list of such exceedances. If No, describe how this was ascertained. Documentary evidence (as outlined in Measure M14) that demonstrates that the entity initiated its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. For all, or a sample of, SOL exceedances, review documentary evidence that demonstrates that the entity initiated its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Requirement 15: Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

Measurement 15: Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

RSAW Audit Guidance: Did the entity have any SOL exceedances during the compliance monitoring period? Yes / No. If No, describe how this was ascertained. If Yes, provide a list of such exceedances and evidence of having informed the Reliability Coordinator of actions to return the system to within limits. Documentary evidence (such as outlined in Measure M15) that demonstrates that the entity informed its Reliability Coordinator of its actions to return the system to within limits when an SOL has been exceeded. For all, or a sample of, SOL exceedances, review documentary evidence that demonstrates the entity informed its RC of its actions to return the system to within limits when an SOL has been exceeded.

TOP-002-4 Operations Planning

Requirement 1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).

Measurement 1: Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

RSAW Audit Guidance: Review documentary evidence that demonstrates that the entity has an Operational Planning Analysis that will allow it to assess whether its planned operations for the next-day within its TOP Area will exceed any of its System Operating Limits (SOLs). Walkthrough a sample of OPAs with the entity.

Requirement 2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1

Measurement 2: Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

RSAW Audit Guidance: Review evidence demonstrating that the entity's Operating Plan addressed potential SOLs that were identified as a result of the Operational Planning Analysis it performed in Requirement R1. Walkthrough a sample of Operating Plans to verify they addressed SOL exceedances as described in Requirement R2.

Requirement 3: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

Measurement 3: Each Transmission Operator shall have evidence that it notified impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

RSAW Audit Guidance: Dated operator logs, email, correspondence, or other evidence, that demonstrates that the entity notified impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

Requirement 6: Each Transmission Operator shall provide its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator.

Measurement 6: Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

RSAW Audit Guidance: Dated operator logs or e-mail correspondence that demonstrates that the entity provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.

TOP-003-3 Operational Reliability Data

Requirement 1:
Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to:

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

Measurement 1: Each Transmission Operator shall make available its dated, current, in force documented specification for data.

RSAW Audit Guidance: Documented specification for the data necessary for the entity to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. In addition to a review of the documentary evidence, the auditor may interview entity representatives to determine if it maintained a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Requirement 3: Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.

Measurement 3: Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.
RSAW Audit Guidance: Data specification(s) received by entity. Electronic or hard copies of data transmittals showing satisfaction of the entity's obligations for the data specifications received.

Requirement 5: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:

5.1. A mutually agreeable format

5.2. A mutually agreeable process for resolving data conflicts

5.3. A mutually agreeable security protocol.

Measurement 5: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.
RSAW Audit Guidance: Data specification(s) received by entity. Electronic or hard copies of data transmittals showing satisfaction of the entity's obligations for the data specifications received.

TOP-010-1(i) Real-time Reliability Monitoring and Analysis Capabilities

Requirement 1: Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include:

1.1. Criteria for evaluating the quality of Real-time data;

1.2. Provisions to indicate the quality of Real-time data to the System Operator; and

1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments

Measurement 1: Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklist, voice recordings, voice transcripts, or other evidence.

RSAW Audit Guidance 1: Review and verify the entity's Operating Process or Operating Procedure addresses the Real-time data necessary to perform Real-time monitoring and Real-time Assessments. Review and verify the entity's Operating Process or Operating Procedure addresses the quality of the Real-time data necessary to perform Real-time monitoring and Real-time Assessments includes; (Part1.1) Criteria for evaluating the quality of Real-time data; (Part 1.2) Provisions to indicate the quality of Real-time data to the System Operator; and (Part 1.3) Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Verify implementation of the Operating Process or Operating Procedure which addresses the quality of the Real-time data necessary to perform Real-time monitoring and Real-time Assessments.

Requirement 3: Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include:

3.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;

3.2. Provisions to indicate the quality of analysis used in Real-time Assessments; and

3.3. Actions to address analysis issues affecting its Real-time Assessments.

Measurement 3: Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R3; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

RSAW Audit Guidance 3: Verify that the Operating Process or Operating Procedure addresses the quality of analysis used in its Real-time Assessment includes: (Part 3.1) Criteria for evaluating the quality of analysis used in its Real-time Assessment; (Part 3.2) Provisions to indicate the quality of analysis used in its

Real-time Assessments; and (Part 3.3) Actions to address analysis quality issues affecting its Real-time Assessments. Verify implementation of the Operating Process or Operating Procedure which addresses the quality of analysis used in its Real-time Assessments.

HMP&L Henderson Municipal Power & Light

Request for Proposals for

Transmission Operator (TOP) and Local Balancing Authority (LBA) Services

UB #18-11-14

November 6, 2018

Submittal Deadline: 2:00 p.m. CT, November 30, 2018

HMP&L

Contents

HMP&L

Services Requested

The City of Henderson, Kentucky, Utility Commission (dba HMP&L) is requesting proposals from qualified providers of NERC compliance services. Specifically, HMP&L is requesting detailed proposals from existing NERC certified Transmission Operators (TOPs) and Balancing Authorities (BAs) to become the contact agent for HMP&L in performing all applicable requirements beginning February 1, 2019, or the earliest possible specified date thereafter.

General Description and Information

HMP&L was established in 1896. In the late 1940's, the City of Henderson established a Utility Commission to manage the daily operations of the electric utility. Currently, 5 citizens are appointed to serve 3-year terms on the City of Henderson Utility Commission. Under Kentucky Revised Statutes ("KRS") Chapter 96, the City Commission, not the Utility Commission, retains the authority to issue debt and set electric rates.

Today, HMP&L has approximately 12,000 meters with an annual peak demand of 107 MW, and annual energy requirements of approximately 625,000 MWh.
HMP&L's annual peak demand and annual energy requirements for the past 5 years are shown in the table below along with demand and energy projections:

Historical and Forecasted Requirements		
Year	*Summer Demand MW*	*Annual Energy MWh*
2013	*108.0*	*617,149*
2014	*108.0*	*639,296*
2015	*109.0*	*625,083*
2016	*107.0*	*624,347*
2017	*110.0*	*612,803*
*2018**	*107.3*	*626,383*
2019	*107.2*	*626,864*
2020	*107.0*	*626,765*
2021	*106.8*	*627,012*
2022	*106.7*	*627,384*
2023	*106.6*	*627,835*
2024	*106.5*	*628,348*

**2018-24 are forecasted values*

Beginning February 1, 2019, HMP&L's Station Two, consisting of 312 MW of coal fired generation will be retired (approved by MISO) and HMP&L will become a non-generating municipal utility. Currently, Big Rivers Electric Corporation (BREC) operates Station Two and provides TOP and BA services to HMP&L as part of their services contracts. BREC is a

HMP&L

Southeastern Reliability Corporation (SERC) registered Local Balancing Authority (LBA), Distribution Provider (DP), Generator Owner (GO), Generator Operator (GOP), Transmission Owner (TO), Transmission Operator (TOP), Transmission Planner (TPL), and a member of MISO. HMP&L's load is part of the BREC LBA and all interconnections are metered and data is Inter-Control Center Communications Protocol (ICCP) compliant. The meter data is provided to MISO via BREC.

Beginning February 1, 2019 BREC has proposed that it will no longer be providing LBA and TOP services to HMP&L. HMP&L is in the process of registering with MISO as a Market Participant (MP), Load Serving Entity (LSE) and Transmission Owner (TO), and anticipates completion of the process prior to February 1, 2019.

HMP&L is a registered Transmission Owner (TO) and Distribution Provider (DP) with NERC and is part of the SERC reliability organization. Only HMP&L's 161kV Transmission Facilities are considered part of the Bulk Electric System (BES) and subject to TO/TOP requirements. Transmission Facilities and sub-transmission facilities submitted to MISO (Attachment 3) applicable to this procurement, and owned by HMP&L include:

- (4) - 69kV tie lines and (2) - 161kV tie lines with BREC
- 34.86 pole miles of 69kV and 22 pole miles of 161kV transmission lines
- (1) – 161kV substation and (6) 69kV substations

HMP&L has a PPA (Power Purchase Agreement) contract with Southeastern Power Administration
("SEPA") for 10 MW of dependable hydro capacity and associated energy that are delivered from the SEPA transmission system to MISO. The hydro contract year includes 15,000 MWh of energy with monthly scheduling parameters of 600 MWh at a minimum and 1,900 MWh at a maximum. Capacity and energy from SEPA is delivered to MISO on firm point-to-point transmission service on the TVA system. Additionally, HMP&L is finalizing the additional power supply to meet its load obligations, and which will replace energy and capacity that was previously supplied from Station Two. All required short-term power supply agreements will be in place by February 1, 2019. A long-term power supply that will begin on June 1, 2019 is currently being evaluated by HMP&L.

Proposal Timeline

Milestone	Date
Issue Request for Proposal	November 6, 2018
Notice of Intent to Propose	November 21, 2018
Proposals Due and Bid Opening	November 30, 2018
Recommendation to and award by HMP&L Board	December 17, 2018
Negotiation of contract	December 18 – December 27, 2018
Final Contract and Award	December 28, 2018

HMP&L

Contact Information

All questions regarding this solicitation that are technical in nature or are intended to clarify the specifications should be directed to HMP&L's consultant:

Terry Naulty
Principal, Naulty Energy Consulting and Advisory LLC
Naultytp1@gmail.com
812-972-1457

Bidders shall not contact any employee of HMP&L without authorization from Terry Naulty.

General Sealed Bid Requirements

Consistent with the procurement regulations of the City of Henderson Utility Commission, this procurement will be awarded by competitive sealed bidding.

In accordance with Kentucky Revised Statutes (KRS) 45A.490 to 45A.494, prior to a contract being awarded to a bidder on a public agency contract, a resident bidder of the Commonwealth of Kentucky will be given a preference over a nonresident bidder registered in any state that gives or requires a preference over bidders from the other state. Therefore, all bidders must complete and submit the following attached forms:

- Form 1: Reciprocal Preference: (Effective February 4, 2011) – (Attachment 2)
- Form 2: Required Affidavit for Bidders, Offerors and Contractors Claiming Resident (Attachment 2)

The bidder must return the reciprocal preference document and the affidavit for bidders claiming resident bidder status (if applicable).

Proposals in response to this RFP will be submitted as a sealed bid via electronic and/or hard-copy format on or before November 30, 2018 by 2p.m. Central Time, when the results will be opened and read aloud at HMP&L's office location.

All bids received after the established due date and time will be considered late and will be marked as such. Late bids will not be considered unless there is clear and convincing evidence that the bid was prepared in the form received by HMP&L prior to the bid deadline and that no other responsive bid from another responsible bidder has been timely received by HMP&L.

No bids shall be opened until the date and time designated in this RFP and all bids received prior to that time shall be kept secure and unopened by HMPL.

Proposed Scope of Work

HMP&L is requesting proposals for any combination of Local Balancing Authority (LBA) and Transmission Operator (TOP) Services, and combined LBA and TOP services beginning on February 1, 2019, or the earliest possible specified date thereafter. The term of the proposed

HMP&L

services shall be for an initial term of three (3) years with two one-year extension options for a maximum of five (5) years. Bidders shall specify renewal provisions for extending the initial term.

The following sections provide the specific requirements for each service type:

Balancing Authority (LBA) Services

HMP&L seeks the services of qualified LBA service providers to provide:

- Comprehensive BA services including all NERC mandated services for Balancing Authorities and any applicable MISO requirements including business practices.
- Proposals will be entertained from parties that propose to provide the development and operation of a stand-alone HMP&L LBA or incorporation of the HMP&L load into an existing MISO LBA.
- The successful bidder will be responsible for NERC and MISO compliance relative to the all applicable requirements and work/business practices as may be in effect at the time of providing such services.
- Any new or modified requirements or work/business practices that become applicable to HMP&L as a result of changes to current requirements and work/business practices by any regulatory body shall be communicated in writing to HMP&L with an associated cost, if any, with sufficient time for consideration by the HMP&L Commission. Upon authorization by HMP&L to perform any such new or modified services, the successful bidder will become responsible for compliance with such requirements.

As previously stated, HMP&L is in the process of registering to become a MISO MP, TO and LSE. Upon approval of membership by the MISO board of directors, MISO will be providing the following NERC functions for HMP&L:

- Reliability Coordinator (RC)
- Transmission Planner (TPL)
- Transmission Service Provider (TSP)
- Planning Authority (PA) and Planning Coordinator (PC)

The successful bidder will be responsible for coordination with applicable NERC functional entities for each NERC standard, and if applicable, any SERC standard, to ensure HMP&L's compliance with such standards.

HMP&L has no interruptible load and has self-determined that the HMP&L BES Facilities are categorized as "Low Impact" per CIP-002. HMP&L has no BES Cyber Systems categorized as high impact or medium impact subject to the Critical Infrastructure Protection (CIP) standards. However, if a bidder has CIP facilities, any extension of the requirement for CIP compliance to HMP&L facilities shall be the responsibility of the successful bidder including CIP 002-5.1a through CIP 014-2 and any new or modified requirements.

The successful bidder shall provide necessary services to HMP&L for compliance with all applicable NERC standards for LBAs. The scope of these services includes the migration of all ICCP meter data and other necessary telecommunications equipment and protocols from HMP&L to the control center of the winning bidder and to MISO as the Reliability Coordinator (RC).

HMP&L

MISO's Business Practice Manual 031-ICCP provides the requirements for ICCP data functionality. Specifically, compliance with the following NERC standards for LBAs are included in the proposed scope of work:

Resource and Demand Balancing Standards

BAL-002-2(i) – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-2(i).pdf

BAL-001-2 – Real Power Balancing Control Performance
https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

BAL-003-1.1 — Frequency Response and Frequency Bias Setting
https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

BAL-005-0.2b — Automatic Generation Control
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=BAL-005-0.2b&title=Automatic%20Generation%20Control&jurisdiction=United%20States

BAL-006-2 — In advertent Interchange
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=BAL-006-2&title=Inadvertent%20Interchange&jurisdiction=United%20States

Communications Standards

COM-001-3 Communications
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=COM-001-3&title=Communications&jurisdiction=United%20States

COM-002-4 – Operating Personnel Communications Protocols
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=COM-002-4&title=Operating%20Personnel%20Communications%20Protocols&jurisdiction=United%20States

Emergency Preparedness and Operations

EOP-004-3 — Event Reporting
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting&jurisdiction=United%20States

EOP-005-2 — System Restoration from Blackstart Resources
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=EOP-005-2&title=System%20Restoration%20from%20Blackstart%20Resources&jurisdiction=United%20States

EOP-008-1 — Loss of Control Center Functionality
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=EOP-008-1&title=Loss%20of%20Control%20Center%20Functionality&jurisdiction=United%20States
EOP-011-1 Emergency Operations
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations&jurisdiction=United%20States

Interchange, Scheduling and Coordination

INT-004-3.1 — Dynamic Transfers
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=INT-004-3.1&title=Dynamic%20Transfers&jurisdiction=United%20States

INT-006-4 — Evaluation of Interchange Transactions
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=INT-006-4&title=Evaluation%20of%20Interchange%20Transactions&jurisdiction=United%20States

INT-009-2.1 — Implementation of Interchange
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=INT-009-2.1&title=Implementation%20of%20Interchange&jurisdiction=United%20States

INT-010-2.1 — Interchange Initiation and Modification for Reliability
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=INT-010-2.1&title=Interchange%20Initiation%20and%20Modification%20for%20Reliability&jurisdiction=United%20States

Modeling, Data and Analysis

MOD-004-1 — Capacity Benefit Margin (BA)
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=MOD-004-1&title=Capacity%20Benefit%20Margin&jurisdiction=United%20States

Personnel Performance, Training and Qualifications

PER-003-1 — Operating Personnel Credentials Standard (RC, TO, BA)
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PER-003-1&title=Operating%20Personnel%20Credentials&jurisdiction=United%20States

PER-005-2 — Operations Personnel Training
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PER-005-2&title=Operations%20Personnel%20Training&jurisdiction=United%20States

HMP&L

Protection and Control

PRC-001-1.1(ii) — System Protection Coordination
https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-001-1.1(ii)&title=System%20Protection%20Coordination&jurisdiction=United%20States

The successful bidder will provide all required functions, documentation, protocols, procedures, of the above standards, any new or modified standards during the performance of the services and any additional LBA requirements applicable to HMP&L as determined by the bidder, MISO, and HMP&L.

Transmission Operator (TOP) Services

HMP&L seeks the services of qualified providers for comprehensive TOP services, to comply with all NERC and SERC requirements for Transmission Operators, and any MISO requirements, including business practices. The successful bidder will be responsible for compliance with all applicable requirements of NERC, SERC and MISO and work/business practices as may be in effect at the time of providing such services. Any new or modified requirements or work/business practices that become applicable to HMP&L because of changes to current requirements and work/business practices by any regulatory body shall be communicated in writing to HMP&L with an associated cost, if any, with sufficient time for consideration by the HMP&L Commission. Upon authorization by HMP&L to perform any such new or modified services, the successful bidder will become responsible for compliance with such requirements.

As previously stated, HMP&L is in the process of registering to become a MISO TO, MP, and LSE. Upon approval of membership by the MISO board of directors, MISO will be providing the following NERC functions for HMP&L:

- Reliability Coordinator (RC)
- Transmission Planner (TPL)
- Transmission Service Provider (TSP)
- Planning Authority (PA) and Planning Coordinator (PC)

The successful bidder will be responsible for coordination with applicable NERC functional entities for each NERC standard, and if applicable, any SERC requirements to ensure compliance with such standards by HMP&L.

HMP&L has no interruptible load and has self-determined that the HMP&L BES Facilities are categorized as "Low Impact" per CIP-002. HMP&L has no BES Cyber Systems categorized as high impact or medium impact subject to the Critical Infrastructure Protection (CIP) standards. However, if a bidder has CIP facilities, any extension of the requirement for CIP compliance to HMP&L facilities shall be the responsibility of the successful bidder including CIP 002-5.1a through CIP 014-2 and any new or modified requirements.

The successful bidder shall provide necessary services to HMP&L for compliance with following NERC standards for TOPs:

HMP&L

Facilities. Design, Connections and Maintenance

FAC-014-2 — Establish and Communicate System Operating Limits (RC, TOP, Planning Authority, TPL) https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=FAC-014-2&title=Establish%20and%20Communicate%20System%20Operating%20Limits&jurisdiction=United%20States

Modeling, Data and Analysis

MOD-001-1a — Available Transmission System Capability (TOP) https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=MOD-001-1a&title=Available%20Transmission%20System%20Capability&jurisdiction=United%20States

MOD-008-1 — TRM Calculation Methodology (TOP that maintain TRM (Transmission Reliability Calculation Margin)) https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=MOD-008-1&title=Transmission%20Reliability%20Margin%20Calculation%20Methodology&jurisdiction=United%20States

MOD-033-1 — Steady-State and Dynamic System Model Validation (Applies to TOP, Planning Coordinator, RC) https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=MOD-033-1&title=Steady%E2%80%90State%20and%20Dynamic%20System%20Model%20Validation&jurisdiction=United%20States

Personnel Performance, Training and Qualifications

PER-003-1 — Operating Personnel Credentials Standard https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PER-003-1&title=Operating%20Personnel%20Credentials&jurisdiction=United%20States

PER-005-2 — Operations Personnel Training https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PER-005-2&title=Operations%20Personnel%20Training&jurisdiction=United%20States

Bidder will provide all required functions, documentation, protocols, procedures, of the above standards, any new or modified standards during the performance of the services and any additional TOP requirements applicable to HMP&L as determined by the bidder and HMP&L.

Proposal Content

All proposals shall provide the following information at a minimum:

- Qualification of the bidder to provide proposed services, including, but not limited to the names of BA, LBA, or TOP customers or balancing areas/transmission systems for which bidder is providing or has provided service to, and how long bidder has been providing applicable services.

- NERC compliance record- bidder shall provide a summary of the results of any NERC or reliability organization's (SERC, RFC, etc.) audits completed in the last 36 months.
- Proposed staff, including an identified Project Manager, and their qualifications/certifications and organization chart detailing functional responsibility for the applicable NERC requirements.
- A description of the recordkeeping and tracking systems used by the bidder to document compliance with applicable NERC/SERC or RTO standards/work practices, reporting and recordkeeping protocols.
- A proposed schedule for integration of ICCP meter telemetry, training, communication protocol development with HMP&L and MISO who will be the Reliability Coordinator (RC) for HMP&L.
- Contract extension terms for each renewal beyond the Initial term.
- Price proposal which shall specify the following:
    - Annual service fee and any applicable annual escalations;
    - Configuration/mobilization/testing costs that are one-time costs for establishing the required telecommunications systems for meter data and communications with MISO and HMP&L; and
    - Any and all other costs proposed by bidder.
- Proposed Services Contract or a Binding Term sheet with the key terms and conditions detailed. HMP&L reserves the right to negotiate terms and conditions of the service contract with the successful bidder.
- Start date for services if not February 1, 2019
- Completed Bid Clarifications and Exceptions Form (Attachment 1) – include any items in the specification of the RFP that bidder will not comply with or will exclude from its provision of services.
- Completed Reciprocal Preference Forms 1 and 2 (Attachment 2)
- Non-Disclosure Agreement (Attachment 6)

Proposal Submission

Bidder shall submit a complete, executed, and sealed electronic and/or hard-copy of their proposal(s) no later than 2:00 PM Central Time on November 30, 2018. Please mark bid envelope: **UB #18-11-14 LBA and TOP Services RFP.**

Please send hard-copy by US Mail or other delivery service to:

UB #18-11-14 LBA and TOP Services RFP
MRS. JOELLA WILSON
CITY OF HENDERSON, KENTUCKY, UTILITY COMMISSION
DBA/HENDERSON MUNICIPAL POWER & LIGHT
100 FIFTH STREET
HENDERSON, KY 42420

Please send electronic copy by email to the following HMP&L RFP email address:

rfp@hmpl.net
(auto reply will confirm receipt)

Proposal are deemed complete with inclusion of: (1) Bidders pricing with clear delineation of services offered to HMP&L, and (2) completed Reciprocal Preference Forms 1 and 2, and (3) completed Bid Clarifications and Exceptions Form. All bids shall be considered firm priced and good for a period of 45 days from submission.

The City of Henderson, Kentucky, Utility Commission (Utility Commission) reserves the right to reject any or all Bids, to waive informalities therein and to consider exceptions and clarifications therein in order to determine the best qualified Bid; to reject any or all non-conforming, non-responsive, unbalanced, or conditional Bids; to reject the Bid of any Bidder if the Utility Commission believes it would not be in the best interest of the Utility Commission to make an award to that Bidder, whether because the Bid is not responsive or the Bidder is unqualified or of doubtful financial ability, or fails to meet any other pertinent standard or criteria established by the Utility Commission. The Utility Commission also reserves the right to negotiate contract terms with successful Bidder. By submitting a Bid to the Utility Commission, the Bidder agrees that such procedures shall be without liability on the part of the Utility Commission for any damage or claim brought by the Bidder because of such rejections or procedures, nor shall the Bidder seek any recourse of any kind against the Utility Commission because of such rejections or procedures. The filing of any Bid in response to this Invitation to Bid shall constitute an agreement of the Bidder to these conditions.

Proposal Evaluation Criteria

HMP&L will evaluate the proposals it receives using the following criteria:

1. Experience of the bidder in providing similar services to municipal or other customers or, in the case of an existing MISO LBAs and TOPs, their history of providing these services to similar LSEs;
2. Compliance history of the bidder;
3. Price;
4. Qualification of proposed staff including the proposed Project Manager; and
5. Ability to transition services from BREC to successful bidder in a timely and cohesive manner.

HMP&L

Attachment 1 – Bid Clarification and/or Exceptions Form

BID CLARIFICATIONS AND/OR EXCEPTIONS

UB #18-11-14

Bidder offers the following clarifications and/or exceptions taken to any requirement or provision of this Invitation to Bid and any proposed modifications or replacement language for each clarification or exception. (If none, so state.)

Bidder understands that unless itemized above, no other clarifications or exceptions to this Invitation to Bid are taken by this Bidder.

____

Bidder

____

Signature of Executing Party

HMP&L

Attachment 2 – Reciprocal Preference Form

Bid #: 18-11-14

RECIPROCAL PREFERENCE: (Effective February 4, 2011)

In accordance with Kentucky Revised Statutes (KRS) 45A.490 to 45A.494, prior to a contract being awarded to a bidder on a public agency contract, a resident bidder of the Commonwealth of Kentucky shall be given a preference over a nonresident bidder registered in any state that gives or requires a preference over bidders from the other state. The preference shall be equal to the preference given or required by the state of the nonresident bidder.

Any individual, partnership, association, corporation, or other business entity claiming resident bidder status shall submit along with its bid response a notarized affidavit (form attached) that affirms that it meets the criteria to be considered a resident bidder as set forth in KRS 45A.494(2). A nonresident bidder shall submit to HMPL, along with its bid response, a copy of its Certificate of Authority to transact business in the Commonwealth of Kentucky as filed with the Kentucky, Secretary of State. The location of the principal office identified therein shall be deemed the state of residency for that bidder. If the bidder is not required by law to obtain said Certificate, the state of residency for that bidder shall be deemed to be that which is identified in its mailing address as provided in its bid.

Bidders must select and check one option below and return this document with bid.

☐ This company is a resident bidder of the Commonwealth of Kentucky **or** this company is a nonresident bidder meeting the following requirements:

1. Is authorized to transact business in the Commonwealth; and
2. Has for one year prior to and through the date of advertisement
   a. Filed Kentucky corporate income taxes; and
   b. Made payments to the Kentucky unemployment insurance fund established in KRS 341.49; and
   c. Maintained a Kentucky workers' compensation policy in effect.

The Required Affidavit for Bidders, Offerors and Contractors Claiming Resident Bidder Status form attached must be completed and returned with bid.

☐ This company is not a resident bidder nor does it meet the requirements as listed in Items 1 and 2 above for nonresident bidders claiming resident status in the Commonwealth.

What is your state of residency? ______________________

Does your state grant "Contract Bid Preference? (circle one) No / Yes

What is the Preference Percentage for your state? __________ %

______________________ Company

______________________ Signature

______________________ Date

______________________ Printed Name

HMP&L

Bid #: 18-11-14

REQUIRED AFFIDAVIT FOR BIDDERS, OFFERORS AND CONTRACTORS CLAIMING RESIDENT BIDDER STATUS

FOR BIDS AND CONTRACTS IN GENERAL:
The bidder or offeror hereby swears and affirms under penalty of perjury that, in accordance with KRS 45A.494(2), the entity bidding is an individual, partnership, association, corporation, or other business entity that, on the date the contract is first advertised or announced as available for bidding:

1. Is authorized to transact business in the Commonwealth; and
2. Has for one year prior to and through the date of advertisement
   a. Filed Kentucky corporate income taxes; and
   b. Made payments to the Kentucky unemployment insurance fund established in KRS 341.49; and
   c. Maintained a Kentucky workers' compensation policy in effect.

Henderson Municipal Power & Light reserves the right to request documentation supporting a bidder's claim of Resident Bidder Status. Failure to provide such documentation upon request may result in disqualification of the bidder or contract termination.

______________________ ______________________
Signature Printed Name

______________________ ______________________
Title Date

Company Name ______________________

Address ______________________

____

____

Subscribed and sworn to before me by:

______________________ (Title) ______________________
(Affiant)

of ______________________ this ________ day of ____________, 20____
(Company Name)

______________________ My commission expires: ____________
Notary Public

[seal of notary]

HMP&L

Attachment 3 - Transmission Facilities Owned by HMP&L

HMP&L Substations Submitted to MISO

Transmission Owner: **City of Henderson, KY, Utility Commission, DBA Henderson Municipal**

Transmission Facilities Transferred to MISO's Functional Control Pursuant to Appendix H (Transmission System Facilities) and Non-transferred Transmission Facilities that are subject to Appendix G (Agency Agreement) of the

Submittal Date: **July 25, 2018**

Substations or Switching Stations

Substation Name	State	Nominal Max kV	Nominal Min kV	Sub ID (Optional)	Comments	Under MISO Functional Control (Appendix H) or Non-Transferred Facilities (Appendix G)	
Transmission Facilities Transferred to MISO's Functional Control Pursuant to Appendix H (Transmission System Facil						H	
HMPL Sub No.4	KY	161	69		High side 161kV	H	161kV high side qualifies as Appendix H transmission
Non-transferred Transmission Facilities that are subject to Appendix G (Agency Agreement) of the Transmission Owi						G	
HMPL Sub No.1	KY	69			69kV in G	G	
HMPL Sub No.2	KY	69			69kV in G	G	
HMPL Sub No.3	KY	69			69kV in G	G	
HMPL Sub No.4	KY	161	69		Low side 69kV	G	
HMPL Sub No.5	KY	69			69kV in G	G	
HMPL Sub No.6	KY	69			69kV in G	G	
HMPL Sub No.7	KY	69			69kV in G	G	

HMP&L

HMP&L Transmission Lines as Submitted to MISO

	A	B	C	D	E	F	G	H	I	J	K
1		**Transmission Owner:**	**City of Henderson, KY, Utility Commission, DBA Henderson**								
2	**Transmission Facilities Transferred to MISO's Functional Control Pursuant to Appendix H (Transmission System Facilities) and Non-transferred Transmission Facilities that are subject to Appendix G (Agency Agreement) of the**										
3		**Submittal Date:**						**July 25, 2018**			
4	**Transmission Lines**										
5	From Substation	To Substation	kV	Circuit ID	Length (miles)	State	Line ID (Optional)	Line Name (Optional)	Segment # (Optional)	Comments	Under MISO Functional Control (Appendix H) or Non-Transferred Facilities
6	Transmission Facilities Transferred to MISO's Functional Control Pursuant to Appendix H (Transmission System Facilities)										H
7	HMPL Sub No.4	Reid EHV Sub (BREC)	161	1	13	KY					H
8	HMPL Sub No.4	Henderson County Tap (BR	161	1	6	KY					H
9											H
10											H
11											H
12											H
13											H
14											H
15											H
16											H
17											H
18											H
19											H
20											H
21											H
22											H
23											H
24											H
25											H
26											H
27											
28	Non-transferred Transmission Facilities that are subject to Appendix G (Agency Agreement) of the Transmission Owners Ag										G
29	HMPL Sub No.1	HMPL Sub No.6	69	1	2.3	KY					G
30	HMPL Sub No.6	HMPL Sub No.3	69	1	1.5	KY					G
31	HMPL Sub No.6	Zion Tap (BREC)	69	1	3	KY					G
32	HMPL Sub No.3	Wolf Hills Tap (BREC)	69	1	3	KY					G
33	HMPL Sub No.1	HMPL Sub No.5	69	1	3.5	KY					G
34	HMPL Sub No.5	HMPL Sub No.4	69	1	2.2	KY					G
35	HMPL Sub No.5	HMPL Sub No.2	69	1	2.1	KY					G
36	HMPL Sub No.4	HMPL Sub No.2	69	1	1.2	KY					G
37	HMPL Sub No.2	HMPL Sub No.7	69	1	2	KY					G
38	HMPL Sub No.7	Reid Switchyard (BREC)	69	1	16	KY					G
39											
40											

HMP&L

HMP&L Transformers as Submitted to MISO

	A	B	C	D	E	F	G
1	**Transmission Owner:**	**City of Henderson, KY, Utility Commission, DBA Henderson Municipal**					
2	**Transmission Facilities Transferred to MISO's Functional Control Pursuant to Appendix H (Transmission System Facilities) and Non-transferred Transmission Facilities that are subject to Appendix G (Agency Agreement) of the**						
3	**Submittal Date:**	**July 25, 2018**					
4	Transformers						
5	Substation Name	Transformer ID	Nominal High Side kV	Nominal Low Side kV	Normal Summer MVA	Comments	Under MISO Functional Control (Appendix H) or Non-Transferred Facilities (Appendix G)
6	Transmission Facilities Transferred to MISO's Functional Control Pursuant to Appendix H (Transmission System Facil						H
7	None						H
8							H
9							H
10							H
11							H
12							H
13							H
14							H
15							H
16							H
17							H
18							H
19							H
20							H
21							H
22							H
23							H
24							H
25							H
26							H
27							
28	Non-transferred Transmission Facilities that are subject to Appendix G (Agency Agreement) of the Transmission Owi						G
29	HMPL Sub No.4	TX1	161	69	50		G
30	HMPL Sub No.4	TX2	161	69	50		G
31							

HMP&L

Attachment 4 - Notice of Intent to Bid Form

Name of Bidder______________________________

Company Representative _____________________________

Representative Title ________________________________

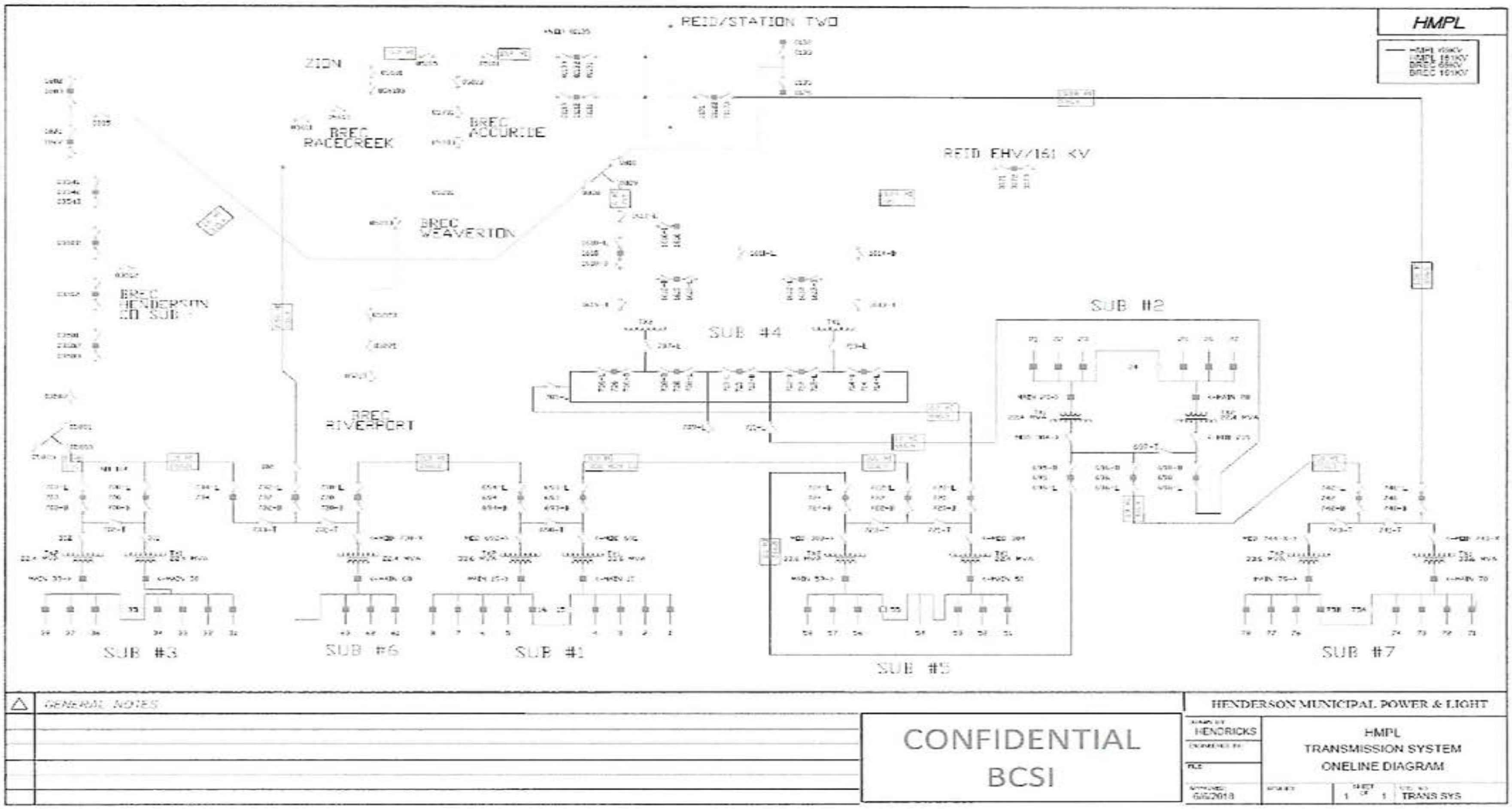
Representative Contact Information
Email Address: _______________________
Office Phone Number: ___________________
Mobile Phone Number ____________________

Expected Proposal (Check as Appropriate)
___ Local Balancing Authority Service
___ Transmission Operator Service
___ Local Balancing Authority and Transmission Operator Services

Please send completed form to:
Terry Naulty
Principal, Naulty Energy Consulting and Advisory LLC
Naultytp1@gmail.com

HMP&L Henderson Municipal Power & Light

Attachment 5 – HMP&L One-line Diagram



HMP&L Henderson Municipal Power & Light

Attachment 6 – Nondisclosure Agreement

CONFIDENTIAL INFORMATION NON-DISCLOSURE AGREEMENT

This NON-DISCLOSURE AGREEMENT is made by the undersigned ("Vendor") and Henderson Municipal Power & Light ("HMP&L"), with its primary address located at 100 5th street, Henderson, Kentucky 42420.

The Vendor has requested that HMP&L disclose to the Vendor certain information, all or a portion of which may be classified by HMP&L as Bulk Electric System Cyber System Information (BCSI); and

The North American Electric Reliability Corporation Critical Infrastructure Protection Standards (NERC CIP), has defined BCSI as "information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems;" and,

The Vendor is working on *Transmission Operator (TOP) and Local Balancing Authority (LBA) Services* requiring access to certain information classified as BCSI.

For purposes of this Agreement, "BCSI" shall mean: (i) all information designated as such by HMP&L, whether furnished before or after the date hereof, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished; and (ii) all reports, summaries, compilations, analyses, notes or other information which contain such information. Written information containing BCSI furnished by HMP&L shall be considered classified information and labeled "**Confidential BCSI**".

Information labeled "**Confidential BCSI**" shall be kept in a secure place. The Vendor shall exercise reasonable care to maintain the confidentiality and secrecy of the classified information, and shall not divulge classified information to any third party without the prior written consent of HMP&L. The Vendor shall use all classified information disclosed by HMP&L only for the referenced work above.

AGREED (Vendor):______________________________

Naulty Energy Consulting and Advisory LLC

December 5, 2018

Brad Bickett
Henderson Municipal Power & Light
100 5th Street
Henderson, KY 42420

Subject: Evaluation of LBA/TOP proposals
UB #18-11-14

Dear Mr. Bickett;

Three offers were received in response to UB #18-11-14, Request for Proposal for Transmission Operator (TO) and Load Balancing Area (LBA) Services dated November 6, 2018. The proposers were Big Rivers Electric Corporation, Hoosier Energy Rural Electric Cooperative, Inc. and Gridforce Energy Management. The Big Rivers proposal was deemed non-responsive as it did not meet the minimum term requirement of 3 years.

Both Hoosier Energy and Gridforce are qualified to perform the services requested. Hoosier Energy is a generation and transmission cooperative that is owned by 17-member distribution cooperatives that are load serving entities in central/southern Indiana and southern Illinois all within the Midcontinent Independent System Operator (MISO) Reliability Transmission Operator (RTO) . Girdforce Energy Management is a third-party provider of NERC services to the utility industry and is a subsidiary of NAES which has been in business for over 20 years. Both proposers have comprehensive control centers with trained and certified NERC operators. Neither proposers are registered with SERC as Balancing Area (BA) or Transmission Operators (TOP) and will require registration. That registration will take at least six months but performance of the BA and TOP functions during the registration process is permitted by NERC.

Consistent with the evaluation criteria specified the RFP, the proposals were evaluated based upon the following criteria:

1. Experience providing TOP and LBA services
2. Compliance history
3. Price
4. Project Manager/team qualifications
5. Transition management

To quantitatively assess each proposal, I have developed a numerical evaluation system that weights the importance of the five evaluation criteria. The numerical rating for the four non-price criteria are as follow:

0 – Unqualified
1 – Minimally qualified
2 – Qualified
3 – Extremely qualified

Price criteria is analyzed separately and simply ranks the lower priced offer as a 2 and the higher price offer as a 1 since both proposers' scope of services have been determined to be responsive to the RFP.

Naulty Energy Consulting and Advisory LLC

Each of the following sections of the evaluation provide my assessment for the five criteria.

1. Experience Providing TOP and LBA Services

1.1. Gridforce Energy Management

Proposer Qualifications	Comments
41 separate balancing areas managed since inception of company	Unmatched expereince in setting up and operating BAs as a third party. Understand commercial risks and have tested service contract.
No active LBA contracts in MISO - thus no potential conflicts of interest	From list of customers, no LSEs in MISO which will require some time to develop the required protocols and establish contacts with MISO technical personnel.
6 separate municipal entities in SERC, 1 in ERCOT	While municipal customers are no longer being serviced by Gridforce, staff understands the communication challenges of a remote provider of BA services.
3 TOP functions for merchant generators	While experience is limited to generators, the substation configurations and amount of BES equipment is very similar to HMP&L subs and equipment.
2 in PJM, 1 in WECC	Not registered as TOP or BA with SERC and has no experience as TOP with MISO as RC, but experience with PJM, a very similar RTO from a transmission and RC operating perspective.
	Will require registration in SERC as TOP

1.2. Hoosier Energy

Proposer Qualifications	Comments
Manages load for 17 member distribution cooperatives - all in MISO	Clearly understand the scope of work for LBA and would effectively look at Henderson as a "new member" from a service perspective. Work for HMPL is a subset of what they provide for member coops because it will not include energy settlement functions and those activities of an MDMA.
	Because Hoosier would not be settling energy or ancillaries, there will be no commerical conflicts. Any concerns regarding optimization of HMP&L transmission system to minimize congestion charges to members will need to be delt with in services agreement.
	No expereince working with Municipal utilities or third party LBAs - establishing procedures and relationships with HMP&L operations personnel will be a new activity for Hoosier.
Currently registered as TOP with RFC.	Has all necessary systems and protocols in place and understands the relationship between MISO and TOPs. Bob Solomon was a driving force behind the establishment of the MISO Operating Protocol between MISO as RC and TOPs.
	Not registered as BA or TOP and has no direct SERC experience as TOP, but reliability standards are the same for all ERO's
	Will require registration in SERC as TOP

2. Compliance History

2.1. Gridforce Energy Management

Proposer Qualifications	Comments
Since 2016, 3 potential violations, both CIP related	HMP&L has no CIP equipment. However, potential violations are cause for concern since they may be indicative of shortcomings in compliance documentation and/or abitlity to stay current on best practices.

2.2. Hoosier Energy

Proposer Qualifications	Comments
No audit findings back through 2012, 2 areas of concern in last reliability organization audit	last three reliability audit have had no violations and only the last one only had 4 recommendations.

3. Price

3.1. **Gridforce Energy Management** – Proposal calls for a monthly service fee and a monthly equipment fee. Both are subject to annual escalation based upon the published Consumer Price Index (CPI). All setup costs are on a pass-through basis with the proposer providing a list of applicable equipment cost.

3.2. **Hoosier Energy** – Proposal calls for a single monthly fee for the first three years. Escalation is computed at 2.5% per year and that assumption is continue for years 4 and 5. All setup costs are on a pass-through basis, but no costs were provided for specific equipment.

Comparative Costs

	Gridforce		Hoosier Energy
	currentl cpi	High cpi	Annual Fee
CPI	0.025	0.028	n/a
Year	Annual Fee	Annual Fee	Annual Fee
1	$ 610,000.00	$ 610,000.00	$ 627,000.00
2	$ 625,250.00	$ 627,080.00	$ 643,200.00
3	$ 640,881.25	$ 644,638.24	$ 658,800.00
4	$ 656,903.28	$ 662,688.11	$ 675,299.99
5	$ 673,325.86	$ 681,243.38	$ 692,213.24
Total FV	$ 3,206,360.39	$ 3,225,649.73	$ 3,296,513.23
NPV	$2,849,306.79	$2,865,791.19	$ 2,929,428.06

4. Project Manager/Staff Qualifications

4.1. Gridforce Energy Management

Proposer Qualifications	Comments
Denise Ayers Project Manager - very experienced in all aspects of setting up and operating BAs and limited TOP	Proposal showed significnat insight into understanding of the timing an how the service agreement would be executed. Project manager and team have implemented many assignments of this nature and understand fully the mechanics of how to accomplish what needs to be done as quickly as possible.
Expereinced staff to support all aspects of service	Staff has a customer focus and 24 hour desk personnel are expereinced in dealing with multiple RTOs on BA and TOP issues.

4.2. Hoosier Energy

Proposer Qualifications	Comments
Bob Solomon, Hoosier's Manager of Compliance, NERC and Power Markets is the proposed project manager. He is very active with MISO.	Clearly the proposed project manager understands the scope of work. However, implementing these services as a third party provider represents a new challenge.
Staff includes the former manager of Transmission Control Center with Duke, and thus knows how to interact with MISO as RC and other TOPs.	24-hour staff and functional leads are extremely qualiifed but will required training. Dealing with HMP&L as a "customer" for services that the staff provides to its internal clients is also a new venture for Hoosier.

5. **Transition Management** – The uncertainty surrounding the termination of services currently being performed by Big Rivers has become more important than when the RFP was issued. This is due to the presence of more facts about Big River's intent and better awareness of the integration time that will be required to fully comply with NERC requirements.

5.1. Gridforce Energy Management

Proposer Qualifications	Comments
Have basics in place by Feb 1. Full implemetation by May 1.	Proposes to use existing ICCP and quick access to SCADA to gain access to data and provide real time monitoring. Aggressive time table but one that understands the scense of urgency. Third party provider structure prioritizes getting systems up and running to meet customer expectations.

5.2. Hoosier Energy

Proposer Qualifications	Comments
Proposed schedule would achieve full standup of service on June 1, 2019	No granularity of implementation schedule provided in proposal. Could be indicative of additional time required to map out the schedule of implementation and the potential to miss the critical path schedule. Proposes to use exisitng staff who are supporting NERC functions for the TO and LSE functions.

6. Evaluation Summary

The quantitative evaluation of the five evaluation criteria for both proposers is provided below:

		Rating		Weighted Rating	
Criteria	Percentage	Hoosier Energy	GridForce	Hoosier Energy	GridForce
Experience	30%	3	3	0.9	0.9
Compliance	15%	3	2	0.45	0.3
Price	25%	1	2	0.25	0.5
Staff/PM	10%	2	3	0.2	0.3
Transition	20%	2	3	0.4	0.6
Total	100%	11	13	2.2	2.6

The quantitative evaluation reveals that Gridforce Energy Management is the lowest evaluated bidder both on a price basis and using the non-price criteria.

7. Recommendation

Based upon the results of the above quantitative evaluation and the following points, I recommend awarding the project to Gridforce Energy Management.

- The culture of Gridforce Energy Management is customer focused and a third-party provider.
- The quality of the proposal offered by Gridforce Energy Management demonstrated a deep understanding of the importance of schedule, and the division of responsibility between HMP&L and Gridforce for complying with NERC requirements.
- Gridforce Energy Management provided a proposed contract for consideration by HMP&L that will enable quicker execution as opposed to the development of a new services contract with Hoosier Energy.

I am reviewing the proposed contract and will provide redlined comments in the next few days for your consideration. Please don't hesitate to call me if you have any questions.

Regards,

Terrance Naulty
Principal
Naulty Energy Consulting and Advisory LLC

COMMISSION MEMO

TO: Chris Heimgartner, General Manager

FROM: Brad Bickett, Reliability Compliance Manager BB

DATE: December 1, 2018

RE: Transmission Operator (TOP) and Local Balancing Authority (LBA) Services
Three (3) Year Agreement with two one-year extension options for maximum of five (5) years.

ACTION REQUESTED

Commission approval to provide a Three (3) Year Local Balancing Authority and Transmission Operator Services Agreement with Fourth and Fifth Year Renewal Options.

BACKGROUND

On November 30, 2018, the City of Henderson Utility Commission received sealed bids for comprehensive services that will fulfill all NERC and SERC requirements applicable to the functions of Transmission Operator and Local Balancing Authority, while following any MISO business practices that may be in effect while providing such services.

Beginning February 1, 2019, HMP&L's Station Two, consisting of 312 MW of coal fired generation will be retired (approved by MISO) and HMP&L will become a non-generating municipal utility. Under the current contracts, Big Rivers Electric Corporation (BREC) operates Station Two and provides TOP and BA services to HMP&L as part of those contracts.

BREC has proposed that it will no longer be providing TOP and LBA services to HMP&L after January 31, 2019. HMP&L is in the process of registering with MISO as a Market Participant (MP), Load Serving Entity (LSE) and Transmission Owner (TO). HMP&L is also currently evaluating new power supply contracts that will be effective on June 1, 2019.

EVALUATION

HMP&L distributed seven (7) Requests for Proposals to provide TOP and LBA services. Three (3) responsive bids were received: Hoosier Energy Rural Electric Cooperative, Inc., Gridforce Energy Management, and Big Rivers Electric Corporation. The Big Rivers proposal was deemed non-responsive as it did not meet the minimum term requirement of 3 years. Gridforce Energy Management was the best evaluated bid that came closest to meeting the Specification.

RECOMMENDATION / MOTION

Motion to provide a Three (3) Year TOP/LBA Agreement with Fourth and Fifth Year Renewal Options for the supply of reliability services in the amount of $600,000 per year for the first year, with one-time implementation costs of $215,400, and annual site maintenance in the amount of $10,000, to Gridforce Energy Management for HMP&L, and to authorize the HMP&L staff to complete negotiations of the terms and conditions for a mutually acceptable Local Balancing Authority and Transmission Operator Services Agreement.

HENDERSON MUNICIPAL POWER & LIGHT

ADDENDUM 1

RFP FOR TOP AND LBA SERVICES

UB #18-11-14

Proposed Scope of Work (revised)

In addition to the requirements specified in the RFP for Transmission Operator Services (TOP and Load Balancing Authority Services (LBA), the following NERC requirements apply. Bidders shall include compliance with the applicable requirements of these standards.

TOP-001-4 - Transmission Operations (BA, TO, TO,GO)
https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-001-4.pdf

Standard TOP-002-4 — Operations Planning (TO, BA)
https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-002-4.pdf

Standard TOP-003-3 — Operational Reliability Data (BA, TO, TOP, GO, GOP, LSE DP)
https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-003-3.pdf

TOP-010-1(i) – Real-time Reliability Monitoring and Analysis Capabilities (TOP, BA)
https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-010-1(i).pdf

Attachment 7 (added)

MISO, as signatory to the ISO Agreement (Transmission Owner Agreement), is required to provide certain reliability functions as prescribed in Module F of the MISO Tariff. Attachment 7 to the RFP entitled "Operating Protocols Between MISO Reliability Coordinator and the Transmission Operators" provides bidders with the specific roles of MIOS and the TOPs with respect to how the TOP will utilize MISO tools, processes and authority to identify and mitigate SOL Exceedances and are consistent with the contractual obligations MISO has under Module F of the MISO Tariff.

All Respondents are asked to submit a signed copy of this Addendum as part of their RFP bid package to acknowledge receipt of the updated information.

____
Respondent

____
Signature of Executing Party

____
Date

HMP&L RECEIVED

NOV 3 0 2018

TIME: BY:

2:02 Jw.lson

BB

Big Rivers

ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Transmission Operator (TOP) and Local Balancing Authority (LBA) Services

UB #18-11-14

Proposal

November 30, 2018

Big Rivers Electric Corporation Proposal Summary

Big Rivers Electric Corporation (Big Rivers or BREC) is pleased to provide this proposal for Transmission Operator (TOP) and Local Balancing Authority (LBA) Services to Henderson Municipal Power & Light (HMP&L). As the incumbent utility currently providing many of these services to HMP&L, Big Rivers is able to meet the February 1, 2019 service schedule with no interruption of service and minimal impact to HMP&L's utility operation. The basic terms of this proposal are included below.

Project Title	UB #18-11-14 TOP and LBA Services
Business Unit	Big Rivers System Operations
Description	Proposal to provide TOP and LBA services to HMP&L
Sponsor	Mike Chambliss, VP System Operations
Project Manager	Chris Bradley, Director Energy Control & Compliance
Term of Contract	4 Months
Initial Cost	\$0.00
On-going Monthly Costs	\$800,000 per Month
Annual Escalation During the Term of the Contract	\$0.00
Start Date of Services	February 1, 2019

PROPOSAL SPECIFICS FOR HMP&L TOP AND LBA SERVICES

1 Qualifications

Big Rivers is a fully integrated transmission owning MISO member and is a Local Balancing Authority (LBA) within the MISO balancing area. Big Rivers is registered with NERC as a Balancing Authority (BA), Transmission Operator (TOP), Distribution Provider (DP), Generator Owner (GO), Generator Operator (GOP), Resource Planner (RP), Transmission Owner (TO), and Transmission Planner (TP). Big Rivers is also party to a Coordinated Functional Registration (CFR) that addresses BA responsibilities with MISO and other MISO members.

Big Rivers currently provides LBA and TOP services to HMP&L and Century Aluminum. Big Rivers previously provided TOP services to Owensboro Municipal Utilities from May 17, 2010 until May 31, 2013.

2 NERC Compliance Record

SERC performed an audit of Big Rivers in 2016. Two possible violations (PV) were identified by SERC. This includes a PRC standard requirement that was found to pose minimal risk to the reliability of the Bulk Power System. This PV was processed as a Compliance Exception. A final determination regarding the second PV is still pending. Confidential audit records can be viewed on-site at Big Rivers Electric Corporation.

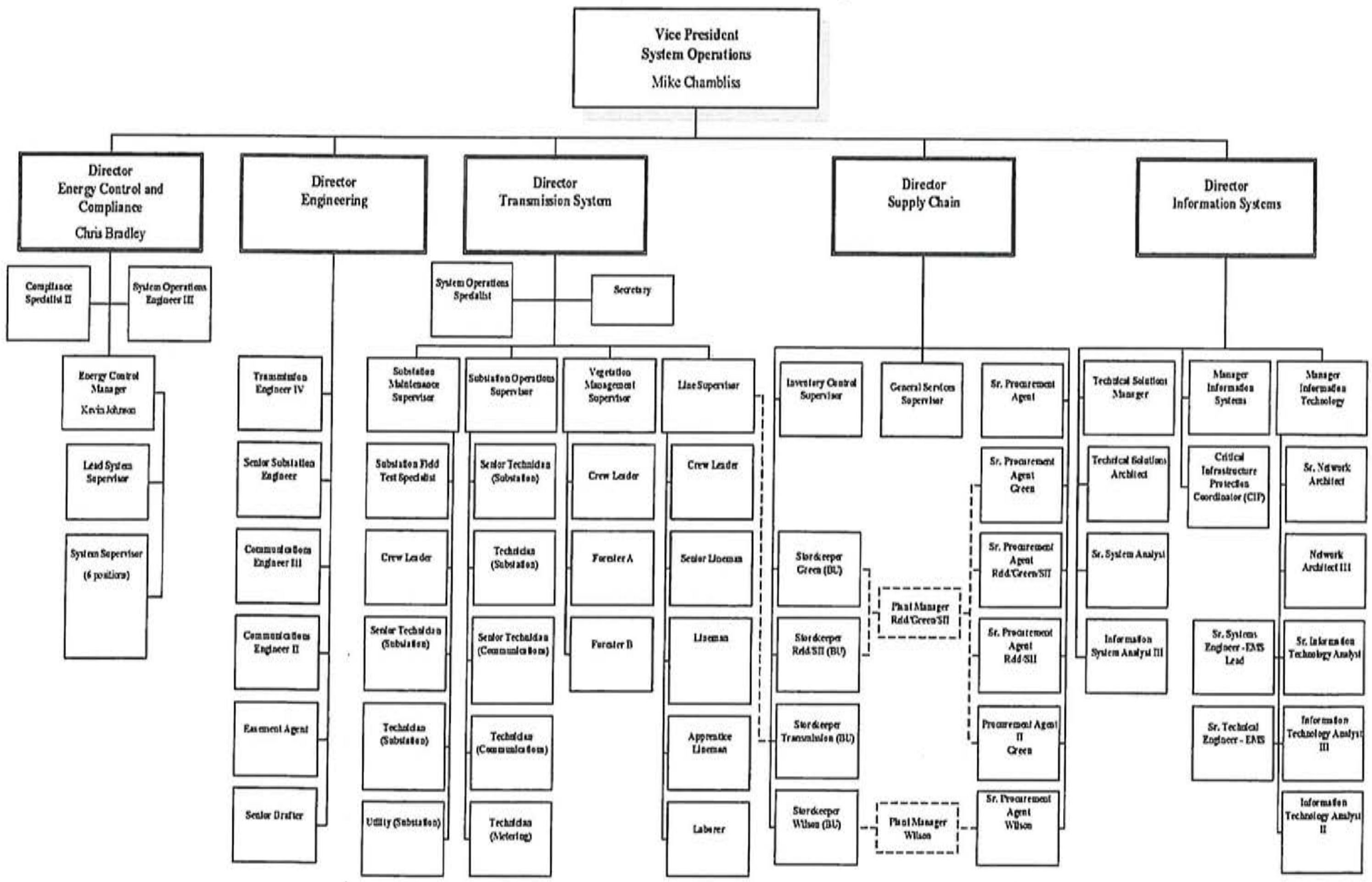
3 Proposed Staff

Big Rivers proposes to utilize existing System Operations staff that currently performs the requested services for HMP&L. This includes departmental personnel from Energy Control, Engineering, Information Systems, and Energy Transmission & Substation (ET&S). The project manager will be Chris Bradley, Director Energy Control & Compliance. Mr. Bradley is a licensed Professional Engineer with almost 30 years of utility experience in the areas of transmission planning and operations. Additional details as well as a System Operations organizational chart follow:

Big Rivers operates a fully staffed primary control center in Henderson, Kentucky. Big Rivers also maintains a completely redundant back-up control center at a remote location. An OSI Energy Management System (EMS) with a fully functioning state estimator and real-time contingency analysis tool is available in both control centers. The primary control center is manned on a 24 hour/7 days per week basis utilizing eight (8) NERC Certified/Reliability Coordinator Level System Operators. Operator experience ranges from 22 years to 4 years with a median average experience of 10 years. Staffing levels include two (2) to three (3) System Operators on day shift Monday through Friday. Second shift staffing Monday through Friday typically includes two (2) System Operators. One (1) System Operator is on shift at all other times. The System Operators work a standard 5-Man/5 week 12 hour rotating shift with a training week built into the schedule. The Big Rivers training program is design to ensure each System Operator stays current with NERC Reliability Standards, MISO Procedures, SERC requirements, and Big Rivers' internal procedures. Continuing education is provided to ensure each System Operator obtains the continuing education hours necessary to maintain NERC System Operator certification. Energy Control System Operators are a diverse group with varying experience in substations, relaying, engineering, and plant operations

Technical support is provided by other Energy Control Department personnel, the Engineering Department, the Information Systems Department, and the ET&S department. This includes licensed Professional Engineers and other technical staff that perform duties related to system planning, power flow/state estimator modeling, voice and data communication support, relay protection, transmission line design, compliance, SCADA/EMS support, maintenance, and other support functions.

TRANSMISSION / OPERATIONS / ENGINEERING / INFORMATION SYSTEMS



11-30-2018

1

4 Recordkeeping

It is the intent and practice of Big Rivers to comply with all federal and state laws and regulations. It is also the practice of Big Rivers to comply with all MISO standards, work practices, and procedures. Consistent with this statement of intent, the compliance program implemented by Big Rivers is designed to ensure compliance with all FERC regulations, including Standards of Conduct; NERC standards; and Kentucky state regulations. All employees are expected to perform their duties in a manner consistent with the expectations, practices, standards of conduct, and other requirements that are specifically included or implied within the documented Internal Controls Program (ICP). The internal controls program developed to ensure compliance with the standards and regulations is based on the COSO Internal Control – Integrated Framework Principles. This framework includes three categories of objectives – operations, reporting, and compliance.

This Internal Compliance Program (ICP) is based on decentralized compliance responsibilities with centralized support. The centralized support is provided by the Director of Energy Control & Compliance and one full-time Compliance Specialist. Support services provided include:

- submittal of most self-certifications as required by SERC
- ensures all reporting deadlines are met for internal and external reporting requirements
- document management
- audit coordination
- internal auditing through compliance support tools
- NERC Alert response coordination
- initiates and builds relationships with internal and external customers and solution providers
- generate monthly compliance report

Compliance support is also provided by the full-time CIP Coordinator. This position is responsible for the CIP Program development, maintenance, and documentation necessary to meet regulatory requirements for the NERC Critical Infrastructure Protection (CIP) standards. The CIP Coordinator directly supports the design, implementation and execution of existing and new compliance support tools; coordinates compliance processes in the Information Systems area; provides monthly input for the Compliance Report.; Outside professional support is also used to perform pre-audit gap analyses and for some CIP standard compliance support functions.

Big Rivers has implemented various processes and tools to mitigate risk and to ensure compliance with all applicable standards and regulations. Most control activities are managed by compliance personnel. A discussion of these control activities follows:
Centralized Support

On an on-going basis, the following duties are performed by compliance personnel:

- Define and communicate to all applicable departments and management their compliance obligations.

- Designate owners for each reporting requirement identified in the standards matrix.
- Ensure that each filing is developed in a manner that allows sufficient time for preparation, internal review, and approval.
- Retain all files and documentation associated with self-certifications within the compliance database (Laserfiche).
- An excel spreadsheet is used to ensure internal documents are updated on time.
- Microsoft Outlook calendar is used for more frequent reoccurring task or reminders.

Compliance Software/Tools

Laserfiche is used for the centralized compliance related document management. This software system allows revision history to be tracked in detail. The software system also provides an electronic approval process and an audit trail. The use of this system was phased-in beginning in mid-2007 with full use implemented in November 2007.

A compliance database was implemented by Big Rivers in 2015. This database is currently being replaced with a Sharepoint based tool to allow more flexibility and transparency with respect to evidence storage and internal auditing. This tool will generate reoccurring reminders, spot checks, tasks, and procedures for the SME or compliance personnel to complete. NERC standards and requirements are downloaded monthly through the NERC website. Big Rivers internal documents are linked to the appropriate standards, along with the necessary tasks, spot checks, or functions that must be completed in order to show compliance. SME's or compliance personnel are required to provide proof of compliance in a timely manner. An evidence link is attached to each request, making it easy for the SME to submit their evidence. Through the work flow process we created, any requests for evidence that have not been completed in a timely manner (i.e. past 30 days), will automatically send an email to the Compliance Officer showing lack of compliance. This tool also allows us to generate monthly, quarterly, and annual reports. While we are still in the process of populating this tool, our goal is to always be in full compliance and keep an open communication channel with appropriate personnel. Therefore, quarterly compliance reports are created and shared with all appropriate personnel.

5 Integration schedule

As the incumbent utility currently providing the requested services to HMP&L, Big Rivers is able to meet the February 1, 2019 service schedule with no interruption of service and minimal impact to HMP&L's utility operation. No changes to the currently provided services are proposed. Consequently, no integration schedule or specific training is necessary or proposed.

6 Contract Extension Terms

A four month term with no provision for contract extensions is proposed (see Bid Clarification and Exception Report – Attachment 1).

7 Price Proposal

Big Rivers proposes a $800,000 per month charge with no escalation over the proposed four month term and no one-time costs.

8 Service Contract/Binding Term Sheet

Big Rivers proposes the following terms:

- All LBA and TOP services currently provided to HMP&L by Big Rivers and currently scheduled to cease on February 1, 2019 will continue to be provided uninterrupted until May 31, 2019.
- Advanced monthly payment is required 15 calendar days prior to the first day of each month in which services will be provided.
- A draft LBA/TOP Services Agreement is attached to the proposal.

9 Service Start Date

A start date of February 1, 2019 is proposed.

10 Bid Clarifications and Exceptions Form (Attachment 1)

A four (4) month term with no provision for contract extensions is proposed as an exception to the requested three (3) years with two one-year extension options defined in the Proposed Scope of Work within the HMP&L Request for Proposal. Additionally, Big Rivers is unable to accept certain terms included in the HMP&L provided Non-Disclosure Agreement (NDA). Therefore, a modified NDA has been executed by Big Rivers and is submitted as part of this response to the HMP&L Request for Proposal. Please see Attachment 1.

11 Reciprocal Preference Forms 1 and 2 (Attachment 2)

Please see Attachment 2.

12 Non-Disclosure Agreement (Attachment 6)

Big Rivers is unable to accept certain terms included in the HMP&L provided Non-Disclosure Agreement (NDA). Therefore, a modified NDA has been executed by Big Rivers and is submitted as part of this response to the HMP&L Request for Proposal. Please see Attachment 1 and Attachment 6.

HMP&L
HENDERSON MUNICIPAL POWER & LIGHT

ADDENDUM 1
RFP FOR TOP AND LBA SERVICES
UB #18-11-14

Proposed Scope of Work (revised)

In addition to the requirements specified in the RFP for Transmission Operator Services (TOP and Load Balancing Authority Services (LBA), the following NERC requirements apply. Bidders shall include compliance with the applicable requirements of these standards.

TOP-001-4 - Transmission Operations (BA, TO, TO,GO)
https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-001-4.pdf

Standard TOP-002-4 — Operations Planning (TO, BA)
https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-002-4.pdf

Standard TOP-003-3 — Operational Reliability Data (BA, TO, TOP, GO, GOP, LSE DP)
https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-003-3.pdf

TOP-010-1(i) – Real-time Reliability Monitoring and Analysis Capabilities (TOP, BA)
https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-010-1(i).pdf

Attachment 7 (added)

MISO, as signatory to the ISO Agreement (Transmission Owner Agreement), is required to provide certain reliability functions as prescribed in Module F of the MISO Tariff. Attachment 7 to the RFP entitled "Operating Protocols Between MISO Reliability Coordinator and the Transmission Operators" provides bidders with the specific roles of MIOS and the TOPs with respect to how the TOP will utilize MISO tools, processes and authority to identify and mitigate SOL Exceedances and are consistent with the contractual obligations MISO has under Module F of the MISO Tariff.

All Respondents are asked to submit a signed copy of this Addendum as part of their RFP bid package to acknowledge receipt of the updated information.

Michael W. Chambliss, Big Rivers Electric Corporation

Respondent

Michael W. Chambliss

Signature of Executing Party

11-30-18

Date

HMP&L

Attachment 1 – Bid Clarification and/or Exceptions Form

BID CLARIFICATIONS AND/OR EXCEPTIONS

UB #18-11-14

Bidder offers the following clarifications and/or exceptions taken to any requirement or provision of this Invitation to Bid and any proposed modifications or replacement language for each clarification or exception. (If none, so state.)

A four (4) month term with no provision for contract extensions is proposed as an exception to the requested three (3) years with two one-year extension options defined in the Proposed Scope of Work within the HMP&L Request for Proposal.

Big Rivers is unable to accept certain terms included in the HMP&L provided Non-Disclosure Agreement (NDA). Therefore, a modified NDA has been executed by Big Rivers and is submitted as part of this response to the HMP&L Request for Proposal.

Bidder understands that unless itemized above, no other clarifications or exceptions to this Invitation to Bid are taken by this Bidder.

Big Rivers Electric Corporation

Bidder

Michael W. Chambliss

Signature of Executing Party

HMP&L

Attachment 2 – Reciprocal Preference Form

Bid #: 18-11-14

RECIPROCAL PREFERENCE: (Effective February 4, 2011)

In accordance with Kentucky Revised Statutes (KRS) 45A.490 to 45A.494, prior to a contract being awarded to a bidder on a public agency contract, a resident bidder of the Commonwealth of Kentucky shall be given a preference over a nonresident bidder registered in any state that gives or requires a preference over bidders from the other state. The preference shall be equal to the preference given or required by the state of the nonresident bidder.

Any individual, partnership, association, corporation, or other business entity claiming resident bidder status shall submit along with its bid response a notarized affidavit (form attached) that affirms that it meets the criteria to be considered a resident bidder as set forth in KRS 45A.494(2). A nonresident bidder shall submit to HMPL, along with its bid response, a copy of its Certificate of Authority to transact business in the Commonwealth of Kentucky as filed with the Kentucky, Secretary of State. The location of the principal office identified therein shall be deemed the state of residency for that bidder. If the bidder is not required by law to obtain said Certificate, the state of residency for that bidder shall be deemed to be that which is identified in its mailing address as provided in its bid.

Bidders must select and check one option below and return this document with bid.

[X] This company is a resident bidder of the Commonwealth of Kentucky **or** this company is a nonresident bidder meeting the following requirements:

1. Is authorized to transact business in the Commonwealth; and
2. Has for one year prior to and through the date of advertisement
   a. Filed Kentucky corporate income taxes; and
   b. Made payments to the Kentucky unemployment insurance fund established in KRS 341.49; and
   c. Maintained a Kentucky workers' compensation policy in effect.

The Required Affidavit for Bidders, Offerors and Contractors Claiming Resident Bidder Status form attached must be completed and returned with bid.

[ ] This company is not a resident bidder nor does it meet the requirements as listed in Items 1 and 2 above for nonresident bidders claiming resident status in the Commonwealth.

What is your state of residency? ______________

Does your state grant "Contract Bid Preference? (circle one) No / Yes

What is the Preference Percentage for your state? % ______________

Big Rivers Electric Corp.
Company

Robert F. Toerne
Signature

November 11, 2018
Date

Robert F. Toerne
Printed Name

HMP&L

Bid #: 18-11-14

REQUIRED AFFIDAVIT FOR BIDDERS, OFFERORS AND CONTRACTORS CLAIMING RESIDENT BIDDER STATUS

FOR BIDS AND CONTRACTS IN GENERAL:

The bidder or offeror hereby swears and affirms under penalty of perjury that, in accordance with KRS 45A.494(2), the entity bidding is an individual, partnership, association, corporation, or other business entity that, on the date the contract is first advertised or announced as available for bidding:

1. Is authorized to transact business in the Commonwealth; and
2. Has for one year prior to and through the date of advertisement
   a. Filed Kentucky corporate income taxes; and
   b. Made payments to the Kentucky unemployment insurance fund established in KRS 341.49; and
   c. Maintained a Kentucky workers' compensation policy in effect.

Henderson Municipal Power & Light reserves the right to request documentation supporting a bidder's claim of Resident Bidder Status. Failure to provide such documentation upon request may result in disqualification of the bidder or contract termination.

Robert F. Toerne
Signature

Robert F. Toerne
Printed Name

Director, Supply Chain
Title

November 30, 2018
Date

Company Name: Big Rivers Electric Corporation

Address: 201 Third Street
Henderson, KY 42420

Subscribed and sworn to before me by:
(Affiant) Donna Frederick (Title) Notary - Senior Procurement Agent
of Big Rivers Electric (Company Name) this 30 day of November, 2018

My commission expires: 5/1/2022

Notary Public Donna S. Frederick

[seal of notary]

HMP&L

Attachment 4 - Notice of Intent to Bid Form

Name of Bidder Big Rivers Electric Corporation

Company Representative Michael W. Chambliss

Representative Title Vice President System Operations

Representative Contact Information
Email Address: Michael.Chambliss@bigrivers.com
Office Phone Number: 270-844-6205
Mobile Phone Number: 270-993-2022

Expected Proposal (Check as Appropriate)
___ Local Balancing Authority Service
___ Transmission Operator Service
_X_ Local Balancing Authority and Transmission Operator Services

Please send completed form to:
Terry Naulty
Principal, Naulty Energy Consulting and Advisory LLC
Naultytp1@gmail.com

HMP&L Henderson Munici• of Power & Li • lit

Attachment 6 — Nondisclosure Agreement

CONFIDENTIAL INFORMATION NON-DISCLOSURE AGREEMENT

This NON-DISCLOSURE AGREEMENT is made by the undersigned ("Vendor") and Henderson Municipal Power & Light ("HMP&L"), with its primary address located at 100 5th street, Henderson, Kentucky 42420.

The Vendor has requested that HMP&L disclose to the Vendor certain information, all or a portion of which may be classified by HMP&L as Bulk Electric System Cyber System Information (BCSI); and

The North American Electric Reliability Corporation Critical Infrastructure Protection Standards (NERC CIP), has defined BCSI as "information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems;" and,

The Vendor is working on *Transmission Operator (TOP) and Local Balancing Authority (LBA) Services* requiring access to certain information classified as BCSI.

For purposes of this Agreement, "BCSI" shall mean: (i) all information designated as such by HMP&L, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished; and (ii) all reports, summaries, compilations, analyses, notes or other information which contain such information. Written information containing BCSI furnished by HMP&L shall be considered classified information and labeled **"Confidential BCSI".**

Information labeled **"Confidential BCSI"** shall be kept in a secure place. The Vendor shall exercise reasonable care to maintain the confidentiality and secrecy of the classified information, and shall not divulge classified information to any third party without the prior written consent of HMP&L. The Vendor shall use all classified information disclosed by HMP&L only for the referenced work above.

AGREED (Vendor): Michael W. Chambliss

BIG RIVERS ELECTRIC CORPORATION

LOCAL BALANCING AUTHORITY AND

TRANSMISSION OPERATING SERVICES AGREEMENT

By and between

BIG RIVERS ELECTRIC CORPORATION

And

HENDERSON MUNICIPAL POWER & LIGHT

Dated ______________________

This LOCAL BALANCING AUTHORITY AND TRANSMISSION OPERATING SERVICES AGREEMENT ("Agreement") is executed as__________, 2018, by and between BIG RIVERS ELECTRIC CORPORATION, an electric cooperative organized and existing under the Laws of the Commonwealth of Kentucky ("Big Rivers"), and the City Utility Commission of the City of Henderson, Kentucky, also known as HENDERSON MUNICIPAL POWER AND LIGHT, a municipal corporation organized and existing under the Laws of the Commonwealth of Kentucky ("HMP&L"), (collectively referred to as "Parties" and individually referred to as a "Party").

WITNESSETH:

WHEREAS, Big Rivers owns and operates an electric utility system comprised of electric generating facilities and transmission facilities located in Kentucky; and

WHEREAS, HMP&L owns and operates an electric utility system comprised of electric generating facilities, transmission facilities and distribution facilities which are operated to supply its retail customers; and

WHEREAS, Big Rivers and HMP&L are directly responsible for complying with Reliability Standards established, administered, and/or enforced by the North American Electric Reliability Corporation ("NERC"), the Electric Reliability Organization ("ERO") and/or the Southeastern Electric Reliability Corporation (SERC), subject to the approval and/or oversight of the Federal Energy Regulatory Commission ("FERC") pursuant to Section 215 of the Federal Power Act ("FPA") as amended by Section 1211 of the Energy Policy Act of 2005; and

WHEREAS, Big Rivers is registered with NERC as a Balancing Authority, Distribution Provider, Generator Owner, Generator Operator, Interchange Authority, Planning Authority, Purchasing-Selling Entity, Resource Planner, Transmission Owner, Transmission Operator, Transmission Planner, and Transmission Service Provider; and

WHEREAS, HMP&L is registered with NERC as a Distribution Provider and Generator Owner,

WHEREAS, beginning on February 1, 2019, HMP&L desires Big Rivers to perform certain Local Balancing Authority and Transmission Operating Services, as specified in this Agreement; and

WHEREAS, Big Rivers is willing to perform such Local Balancing Authority and Transmission Operating Services, subject to the terms and conditions of this Agreement.

NOW, THEREFORE, in consideration of the mutual promises, covenants and agreements set forth herein, the Parties do hereby agree with each other, for themselves and their successors and assigns, intending to be legally bound, as follows:

ARTICLE I
GOVERNANCE AND TERM

Section 1.1: This Agreement shall be effective on February 1, 2019, ("Effective Date"), and shall continue in effect until termination on June 1, 2019, except as otherwise provided in Section 1.4, OR 2.7.

Section 1.2: Termination of this Agreement shall not relieve the Parties of any cost obligations or other obligations and liabilities related to this Agreement that were incurred prior to the effective date of termination of this Agreement.

Section 1.3: Termination of this Agreement terminates all services provided under this Agreement and any continuing obligations to provide such services.

Section 1.4: Except as otherwise provided in Section 2.7 of this agreement, if Big Rivers determines to cease providing Local Balancing Authority Services and Transmission Operator Services to HMP&L, other than as provided in Section 9.7 of this Agreement, Big Rivers shall give written notice to terminate this Agreement; provided, however that Big Rivers will continue to provide the services covered by this Agreement to HMP&L so as to allow HMP&L sufficient time to provide or obtain full replacement of the Local Balancing Authority Services and Transmission Operator Services. In no event shall Big Rivers be required to provide the services for more than 60 days after giving written notice to HMP&L.

Section 1.5: This Agreement is based on the existence of NERC as the ERO and the applicability of the NERC Reliability Standards, the NERC Glossary of Terms, and other NERC policies and procedures. To the extent that NERC ceases to exist in its current form and/or is replaced with another ERO with additional authority over a Party's transmission system, the Parties shall promptly meet to determine whether to revise this Agreement to reflect the new reliability entity and the Parties' obligations in light of the new reliability entity or to terminate this Agreement in accordance with Sections 1.1 or 1.4.,

Section 1.6: Any capitalized terms used in this Agreement that are not defined in this Agreement (including Schedule A attached hereto), in the Big Rivers Operating Procedures and Guidelines, or in the Operating Protocols shall have the meaning established in the NERC Glossary of Terms, as published on the NERC website and as may be modified from time to time. In the event of any conflicts among definitions of capitalized terms, such definitions shall be given the following order of priority: (1) this Agreement; (2) Big Rivers Operating Procedures and Guidelines; (3) Operating Protocols; and (4) NERC Glossary of Terms. For purposes of this Agreement, the term

"Reliability Standard" shall mean a Reliability Standard approved by FERC as mandatory and enforceable by NERC and SERC.

ARTICLE II
SCOPE OF TRANSMISSION OPERATING SERVICES

Section 2.1: Under this agreement, Big Rivers shall provide HMP&L with the Local Balancing Authority Services (LBAS) Transmission Operating Services ("TOS") described in Attachment A in accordance with Good Utility Practice, all Federal Power Act obligations, FERC obligations applicable to transmission system operators, NERC and SERC Reliability Standards, the Big Rivers Operating Procedures and Guidelines in effect at that time, any Operating Protocols jointly developed by the Parties, and the terms and conditions specified in this Agreement.

Section 2.2: HMP&L may from time to time request that Big Rivers perform certain Additional Local Balancing Authority Services ("ALBAS") and Additional Transmission Operating Services ("ATOS"). At Big Rivers' sole discretion, Big Rivers may provide such ALBAS and ATOS, upon the terms agreed upon by the Parties. Under no circumstances shall Big Rivers commence performance of any Additional Local Balancing Authority Services or Additional Transmission Operating Services prior to receiving a Request for ALBAS or ATOS from the Designated Representative of HMP&L.

Section 2.3: HMP&L grants Big Rivers the Operational Authority to issue directives to HMP&L personnel to alleviate operating emergencies and control HMP&L transmission facilities specified in Attachment C. Big Rivers has issued an authorization letter "System Supervisor/Associate System Supervisor Authority" which authorizes Big Rivers System Supervisors and Associate Supervisors to take what actions are needed to alleviate System Operating Emergencies as identified under Big Rivers procedure EC-TOP-1 & other Big Rivers procedures identified within Attachment D. In addition, HMP&L has provided Big Rivers a letter authorizing Big Rivers System Supervisor/Associate System Supervisors and HMP&L System Operator/Dispatchers to take what actions are needed to alleviate HMP&L System Operating Conditions and Emergencies.

Section 2.4: HMP&L reserves the right to monitor and inspect any and all LBAS and TOS performed by Big Rivers, its agents or subcontractors pursuant to this Agreement; provided, however, HMP&L shall perform such monitoring and inspection in a manner which will not materially interfere with the performance of such LBAS and TOS by Big Rivers, its agents or subcontractors.

Section 2.5: Each Party recognizes its obligation to participate in compliance audits and other activities as specified in the annual SERC Compliance Monitoring and Enforcement Program, including SERC Audits, Compliance Investigations, Spot Checks and Self-Certifications. Big Rivers agrees to provide all documentation requested by HMP&L relating to performance of LBAS and TOS specified in this Agreement and to provide, to the extent practicable, any Big Rivers subject-matter experts for participation in such audit activities. HMP&L agrees to reimburse Big Rivers for the cost of such services and subject-matter expert participation.

Section 2.6: HMP&L reserves the right to conduct audits annually, and in preparation for any SERC Audit of Big Rivers' performance under this Agreement and agrees to give Big Rivers at least 30 days prior written notice, if possible. Big Rivers shall provide HMP&L any analysis, reports, case studies, models, projections or other intermediate work products used to provide the LBAS TOS and generate the Transmission Operations Information, Data and Reports provided in Attachments A and B, respectively. HMP&L agrees to reimburse Big Rivers for the costs incurred by Big Rivers related to the audits specified herein.

Section 2.7: In the event HMP&L discovers that any LBAS, ALBAS, TOS or ATOS performed by Big Rivers fails to conform to the requirements specified in this Agreement, HMP&L may request that Big Rivers, (a) promptly correct or re-perform such non-conforming LBAS, ALBAS, TOS or ATOS to conform with the requirements specified in this Agreement to the extent that such LBAS, ALBAS, TOS or ATOS can be corrected or re-performed and (b) develop a new process, procedure or manner for performing such non-conforming LBAS, ALBAS, TOS or ATOS on a prospective basis, approved by the Parties Designated Representatives, and such that Big Rivers' performance of such LBAS, ALBAS, TOS or ATOS conforms to the requirements specified in this Agreement. In the event Big Rivers fails, or is unable, to remedy such nonconforming TOS or ATOS within a reasonable time, HMP&L may terminate this Agreement upon at least ten (10) days written notice, and with such termination becoming effective on the last Day of a Month. HMP&L's right to terminate this Agreement under this Section 2.7 shall be in addition to any and all other rights that HMP&L has under the terms of this Agreement.

ARTICLE III
PROCEDURES AND GUIDELINES

Section 3.1: Big Rivers shall use the Big Rivers Operating Procedures and Guidelines specified in Attachment D in providing services under this Agreement. Prior to the Execution Date, Big Rivers shall provide HMP&L with a copy of the Big Rivers Operating Procedures and Guidelines consistent with the directory set forth in Attachment D. Such Big Rivers Operating Procedures and Guidelines shall remain in effect unless modified by Big Rivers pursuant to Section 3.2 herein. Big Rivers may, in its sole discretion, fulfill its obligation to provide HMP&L with copies of the Big Rivers Operating Procedures and Guidelines by providing electronic copies of the relevant documents to HMP&L or by providing HMP&L online access to a current version of the documents maintained by Big Rivers. The Parties acknowledge and agree that the Big Rivers Operating Procedures and Guidelines, as they may be modified from time to time in accordance with Section 3.2 herein, and other documentation provided to HMP&L in accordance with this Agreement are Confidential Information and shall be governed by the requirements of Article V, Section 5.3 herein.

Section 3.2: As soon as practicable after any modifications to the Big Rivers Operating Procedures and Guidelines take effect, Big Rivers shall provide HMP&L with a complete copy of the revised Big Rivers Operating Procedures and Guidelines; provided, however, Big Rivers may, in its sole discretion, fulfill its obligation to provide HMP&L with copies of the revised Big Rivers Operating Procedures and Guidelines by providing electronic copies of the relevant documents to HMP&L or by providing HMP&L online access to then current version of the documents maintained by Big Rivers.

Section 3.3: The Parties acknowledge and agree that Operating Protocols are necessary to implement the Local Balancing Authority Services and Transmission Operating Services and will jointly be developed by Big Rivers and HMP&L. Such Operating Protocols may be revised from time to time as required by each Party. Any proposed updates or revisions shall be forwarded to the other Party for review and approval. The Parties agree that the Operating Protocols are included in Attachment E to this Agreement.

ARTICLE IV
LOCAL BLANCING AUTHORITY AND TRANSMISSION OPERATIONS INFORMATION, DATA AND REPORTS

Section 4.1: HMP&L shall provide Big Rivers with the Local Balancing Authority and Transmission Operations Information, Data and Reports specified in Attachment B1. The provision of such Local Balancing Authority and Transmission Operations Information, Data and Reports shall include electronic data transfer, Inter Control Center Protocol (ICCP), and other provisions, as further specified in Attachment B 1. The Parties acknowledge and agree that the Local Balancing Authority and Transmission Operations Information, Data and Reports provided by HMP&L to Big Rivers in accordance with this Section 4.1 is Confidential Information and shall be governed by the requirements of Article V Section 5.3 herein. The Local Balancing Authority and Transmission Operations Information, Data and Reports provided by HMP&L to Big Rivers shall be used by Big Rivers solely for performing its obligations and carrying out its responsibilities under this Agreement.

Section 4.2: Big Rivers shall provide HMP&L with Local Balancing Authority and Transmission Operations Information, Data and Reports as specified in Attachment B2. The Provision of such Local Balancing Authority and Transmission Operations Information, Data and Reports shall include electronic data transfer, ICCP and other provisions as further specified in Attachment B2. To the extent that the Midcontinent Independent System Operator ("MISO") is the source of such Transmission Operations Information, Data and Reports, Big Rivers shall provide it to HMP&L in a manner consistent with Big Rivers' obligations hereunder and in conformance with any applicable confidentiality agreements including the NERC Operating Reliability Data Confidentiality Agreement. The Parties acknowledge and agree that the Local Balancing Authority and Transmission Operations Information, Data and Reports provided to HMP&L in accordance with this Section 4.2 is Confidential Information and shall be governed by the requirements of Article V Section 5.3 herein. The Local Balancing Authority and Transmission Operations Information, Data and Reports provided by Big Rivers to HMP&L shall be used by HMP&L solely for performing its obligations and carrying out its responsibilities under this Agreement. HMP&L agrees to reimburse Big Rivers for the costs associated with providing of such Local Balancing Authority and Transmission Operations Information, Data and Reports as specified herein in the annual fee.

Section 4.3 In the event the Local Balancing Authority and Transmission Operations Information, Data and Reports provided by a Party under Section 4.1 and 4.2 is utilized by the other Party to develop any finished work product on a routine basis that is not specified in Attachments A, B1 or B2, such developing Party shall provide the other Party with a copy of such finished work product. Thereafter, the Parties shall modify Attachments A, B1 or B2 to include such finished work product and the developing Party shall provide such finished work product to the other Party in accordance with Section 4.1 or 4.2.

Section 4.4: HMP&L shall provide any information, as required, for upgrades to telecommunications facilities, control room facilities, assistance with engineering model updates, engineering studies, or other items deemed additional services from Big Rivers for requirements to perform Local Balancing Authority Services and Transmission Operator Services for HMP&L.

ARTICLE V
STANDARDS OF PERFORMANCE

Section 5.1: Big Rivers shall perform its responsibilities in accordance with the requirements of the applicable NERC Reliability Standards and SERC supplemental requirements, and Good Utility Practice. For the purposes of this Agreement, "Good Utility Practice" shall mean any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts that, in a person's exercise of reasonable judgment in light of the facts as known to that person at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to include the range of acceptable practices, methods, or acts generally accepted in the region.

Section 5.2: Big Rivers shall use all reasonable efforts to communicate promptly with HMP&L to notify it of transmission reliability concerns affecting HMP&L systems or facilities.

Section 5.3: Big Rivers and HMP&L shall treat their activities pursuant to this Agreement and the information they obtain pursuant to this Agreement as confidential. Each Party shall sign the NERC Operating Reliability Data Confidentiality Agreement and shall treat the activities undertaken and Confidential Information obtained pursuant to this Agreement as transmission operations and transmission system information pursuant to such NERC Operating Reliability Data Confidentiality Agreement.

ARTICLE VI
LIABILITY AND INDEMNIFICATION

Section 6.1: Big Rivers shall act in good faith to perform the obligations assigned to it under this Agreement. Because the work performed by Big Rivers depends upon the information provided by HMP&L and numerous other entities, Big Rivers shall have no responsibility for the accuracy and/or completeness of such information.

Section 6.2: Neither Party shall be liable to the other Party under this Agreement (by way of indemnification, damages or otherwise) for any indirect, incidental, exemplary, punitive, special or consequential damages, except in the case of gross negligence or willful misconduct.

Section 6.3: Neither Party shall be liable under this Agreement to the other Party for any claim, demand, liability, loss, or damage, whether direct, indirect, or consequential, or whether arising in tort, contract or other theory of law or equity, incurred by the other Party or its customers, resulting from the separation of the Party's systems in an emergency or interruption.

Section 6.4: Except as otherwise provided in Section 6.3 of this Agreement, each Party ("Indemnifying Party") shall indemnify, release, defend, reimburse and hold harmless the other Party and its Affiliates, and their respective directors, officers, employees, principals, representatives and agents (collectively, the "Indemnified Parties") from and against any and all claims, demands, liabilities, losses, causes of action, awards, fines, penalties, litigation, administrative proceedings and investigations, costs and expenses, and attorney fees (each, an "Indemnifiable Loss") asserted against or incurred by any of the Indemnified Parties arising out of, resulting from or based upon the gross negligence or willful misconduct of the Indemnifying Party. HMP&L shall indemnify, release, defend, reimburse and hold harmless Big Rivers and its Affiliates, and their respective directors, officers, employees, principals, representatives and agents from and against any and all Indemnifiable Losses asserted against or incurred by any of the Indemnified Parties arising out of, resulting from or based upon the actions or omissions of either Party and their Affiliates and their respective directors, officers, employees, principals, representatives, agents or contractors, relating to this Agreement, except those actions and omissions on the part of Big Rivers that constitute gross negligence or willful misconduct.

ARTICLE VII
RELIABILTY COORDINATOR DIRECTIVES RECEIVED BY BIG RIVERS DURING PERFORMANCE OF TRANSMISSION OPERATING SERVICES

Section 7.1: In accordance with its responsibilities under Section 2.1 of this Agreement, Big Rivers is authorized to, and shall, direct and coordinate timely and appropriate actions by HMP&L in order to avoid adverse effects on interregional bulk power reliability. Big Rivers is also authorized to coordinate, or cooperate in, interregional activities to relieve problems experienced by other transmission systems.

Section 7.2: During any period when the Reliability Coordinator, MISO, determines that an actual or potential threat to transmission system reliability exists, and that such threat may impair the reliability of a transmission system, Big Rivers, acting on behalf of HMP&L, shall comply with any direction of the Reliability Coordinator to take whatever actions are necessary, consistent with Good Utility Practice and in accordance with the applicable NERC Reliability Standards and SERC supplemental requirements.

Section 7.3: Big Rivers shall be responsible for communicating to HMP&L any directives given HMP&L by the Reliability Coordinator.

Section 7.4: Big Rivers, acting on behalf of HMP&L, may review any directive from the Reliability Coordinator specified in Section 7.2, after the fact, to determine if it is, in its judgment, consistent with Good Utility Practice, applicable NERC Reliability Standards and SERC supplemental requirements, and its legal responsibilities and, if Big Rivers acting on behalf of HMP&L determines that the directive is not in accordance with Good Utility Practice or applicable NERC Reliability Standards and SERC supplemental requirements, it shall immediately so notify HMP&L and the Reliability Coordinator. Such notification shall include: a) complete information outlining the basis for Big Rivers' determination that the directive is not in accordance with Good Utility Practice and applicable NERC Reliability Standards and SERC supplemental requirements and b) the alternative action that Big Rivers, acting on behalf of HMP&L, would prefer to take to alleviate the problem addressed by the Reliability Coordinator's directive.

ARTICLE VIII
[RESERVED]

ARTICLE IX
FEES

Section 9.1: Compensation to Big Rivers for services under this Agreement shall be made in full in advance of February 1, 2019.

Section 9.2: If HMP&L fails to pay any undisputed invoice amount within 5 business days after receipt of written notice of its delinquency, Big Rivers may immediately terminate this Agreement by written notice of termination to HMP&L.

ARTICLE X
MISCELLANEOUS

Section 10.1: Notice. Except as otherwise specified herein, any notice required or authorized by this Agreement shall be deemed properly given to a Party when sent to its Designated Representative by facsimile or other electronic means (with a confirmation copy sent by United States mail, first-class postage prepaid), by hand delivery, or by United States mail, first-class postage prepaid. The Parties' Designated Representatives are as follows:

Big Rivers Electric Corporation

Name: Michael W. Chambliss
Fax number: (270) 827-0183
Electronic mail address: michael.chamblisst@bigrivers.com
Street address:

201 Third Street
Henderson, KY 42420

Henderson Municipal Power & Light

Name: Chris Heimgartner
Fax number: (270)
Electronic mail address:
United States mail address:

A Party may change its Designated Representative by providing written notice of the change to the other Party. Changes in the designated representatives shall not require formal amendment of this Agreement.

Section 10.2: **No Waiver.** Any waiver at any time by either Party of its rights with respect to a default or any other matter arising in connection with this Agreement shall not be deemed to be a waiver with respect to any subsequent default or other matter; provided, however, a Party that is properly notified of a duly scheduled meeting and fails to have an operating representative attend shall not be entitled to a waiver from complying with any decisions made at such meeting.

Section 10.3: **No Assignment.** Neither Party shall sell, assign, or otherwise transfer any or all its respective rights hereunder, or delegate any or all of its respective obligations under this Agreement, without the express written consent of the other Party, or except as otherwise provided in this Agreement.

Section 10.4: **No Third Party Beneficiaries.** Nothing in this Agreement is intended to confer benefits upon any person or entities not a Party to this Agreement. Nothing in this Agreement shall be construed as a stipulation for the benefit of others, and no third party shall be entitled to enforce this Agreement against any Party hereto.

Section 10.5: **Headings.** The descriptive headings in this Agreement have been inserted for convenience of reference only, and shall in no way modify or restrict any of the terms and provisions hereof.

Section 10.6: **Force Majeure.** A Party shall not be responsible for, liable for, or deemed in breach of this Agreement for any delay or failure in the performance of its respective obligations under this Agreement (except for obligations to pay money, which shall not be excused due to Force Majeure) to the extent such delay or failure is due solely to circumstances beyond the reasonable control of the Party experiencing such delay or failure (such Party referred to herein as the "Non-Performing Party"), including but not limited to acts of God; labor disturbance; extraordinarily severe weather conditions; war; terrorism; riots; requirements, actions, or failures to act on the part of governmental authorities preventing or delaying performance; fire; damage to or breakdown of necessary facilities; or any other causes, whether or not of the same class or kind as those specifically identified above, which are not within the control of the Non-Performing Party (such causes hereinafter called "Force Majeure"); provided that:

(i) The Non-Performing Party gives the other Party written notice within two (2) Business Days of the Force Majeure, with details to be supplied within ten (10) Days further describing the particulars of the event;

(ii) The suspension of performance is of no greater scope and of no longer duration than is attributable to the Force Majeure;

(iii) The Non-Performing Party uses all reasonable efforts to remedy its inability to perform;

(iv) When the Non-Performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect; and

(v) The Force Majeure was not caused by or connected with the Non-Performing Party's negligent or intentional acts, errors, or omissions, or its failure to comply with any law, rule, regulation, order, or ordinance, or its breach or default of this Agreement.

Section 10.7: <u>Compliance with Laws.</u> This Agreement is made subject to present and future applicable local, state, and federal laws and to the regulations or orders of any local, state, or federal regulatory authority having jurisdiction over the matters set forth herein. Performance under this Agreement is conditioned upon securing and retaining such local, state, or federal approvals, grants, or permits as may from time to time be necessary with respect to such performance. Each Party shall use due diligence and good faith efforts to secure and retain all such approvals, grants, and permits within such time as shall permit it to perform all of its obligations under this Agreement.

Section 10.8: <u>Entirety.</u> This Agreement constitutes the entire Agreement between the Parties relating to the subject matters identified in this Agreement. There are no prior or contemporaneous agreements or representations (whether oral or written) affecting the subject matter other than those herein expressed. Any amendment or modification to this Agreement shall be enforceable only if reduced to writing and executed by the Parties.

Section 10.9: <u>Governing Law and Choice of Forum.</u> This Agreement and the rights and duties of the Parties relating to this Agreement shall be governed by and construed in accordance with applicable

Kentucky and federal law.

Section 10.10: Creates No Special Relationship. This Agreement shall not be construed to create an association, joint venture, partnership, or other legal entity between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of the other Party, except as expressly provided herein.

Section 10.11: Joint Preparation of Agreement. This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against any one Party as a result of the preparation, substitution, submission, or other event of negotiation, drafting, or execution hereof.

Section 10.12: Counterparts. This Agreement may be executed in several counterparts, each of which shall be considered an original and all of which shall constitute but one and the same instrument.

Section 10.13: Power and Authority. Each Party represents and warrants that: (i) its signatory has the necessary power and authority to execute this Agreement and bind it; (ii) it has the power and authority to enter into and perform its obligations under this Agreement; and (iii) entering into and performing this Agreement does not violate or conflict with its charter, bylaws, other governing documents, licenses, consents, regulatory approvals, any applicable law, any applicable order or judgment of any court or regulatory agency, or any agreement to which it is a party.

Section 10.14: Non-solicitation. Each Party agrees that for one year following the termination of this Agreement it will not solicit any employee of the other Party who has been certified by NERC to perform transmission operator services.

IN WITNESS WHEREOF, each Party has caused this Agreement to be executed by its duly authorized representative.

HENDERSON MUNICIPAL POWER & LIGHT

By: ______________________________

Name:

Title:

BIG RIVERS ELECTRIC CORPORATION

By:

Name:

Title:

SCHEDULE A

DEFINITIONS

"Administrative Responsibility" — shall mean the responsibility to evaluate and authorize requests to change the operating position of a Network Energizing Device or Network Function Switch by Big Rivers or HMP&L as further specified in the Assignment Table, Attachment C. This responsibility includes (a) developing and issuing switching instructions and issuing Hold Tags, as applicable, for each Network Energizing Device and Network Function Switch that is in a temporary operating position and (b) developing and issuing switching instructions and holding Clearances, as applicable.

"Assignment Table" — shall mean the table describing the assignment of Administrative Responsibility and Physical Operating Responsibility for HMP&L Operational Devices as specified in Attachment C. Such Assignment Table may be modified or revised from time to time by mutual agreement of the Agreement Designated Representatives.

"Clearance" - has the meaning set forth in the current version of the *Operating Protocol Attachment E*

"Confidential Information" - shall mean any and all confidential, proprietary, or secret information (including without limitation, present and future business plans, formulae, processes, models, designs, photographs, plans, drawings, schematics, sketches, samples, equipment, equipment performance reports, customer lists, pricing information, studies, reports, findings, inventions, ideas, specifications, parts lists, technical data, data bases, computer programs, flow charts, algorithms and other business and technical information which are used in the performance of this Agreement) which is disclosed by one of the Parties to the other Party, in written or other tangible form marked "Confidential" on each page of any material to be considered confidential, or, if disclosed orally or visually, that is identified at the time as confidential; provided that the Party receiving such information shall have no obligation to treat any such information not marked as "Confidential" as confidential until informed by the other Party that such information is to be treated as confidential.

"Big Rivers Operating Procedures and Guidelines" - shall mean the practices, procedures, guidelines and standards agreed to by the Parties in accordance with Article 3 and used by Big Rivers in the delivery of Local Balancing Authority and Transmission Operating Services to HMP&L under this Agreement, as further specified in Attachment D.

"Designated Representative" — the representative of each party responsible for administering, authorizing and approving changes to this agreement.

"Hold Tag" - shall have the meaning set forth in the current version of the Operating Protocol Attachment E

"Transmission Operating Services" - shall mean the Local Balancing Authority and Transmission Operating Services contained within Attachment A or the Equivalent.

"Transmission Operations Information, Data and Reports" - shall mean the Transmission Operations Information, Data and Reports contained within Attachments B1 and B2.

"Physical Operating Responsibility" — shall mean the responsibility of Big Rivers or HMP&L as further specified in the Assignment Table, Attachment C, to monitor and control certain Network Energizing Devices and Network Function Switches via local control and/or remote control systems.

Attachment A

LIST OF TRANSMISSION OPERATING SERVICES PERFORMED BY BIG RIVERS

(To be Jointly Developed by Big Rivers and HMP&L after Agreement Execution)

Attachment B1

LOCAL BALANCING AUTHORITY AND TRANSMISSION OPERATIONS INFORMATION, DATA AND REPORTS Information, Data and Reports HMP&L shall provide to Big Rivers for Big Rivers to perform the Local Balancing Authority and Transmission Operating Services:

(To be Jointly Developed by Big Rivers and HMP&L after Agreement Execution)

Attachment B2

LOCAL BALANCING AUTHORITY AND TRANSMISSION OPERATIONS INFORMATION, DATA AND REPORTS: Information, Data and Reports Big Rivers shall provide to HMP&L upon Big Rivers' performance of the Local Balancing Authority and Transmission Operating Services specified in Attachment A:

(To be Jointly Developed by Big Rivers and HMP&L after Agreement Execution)

Attachment C

ASSIGNMENT TABLE

(To be Jointly Developed by Big Rivers and HMP&L after Agreement Execution)

Attachment D

DIRECTORY OF POLICIES, PROCEDURES, GUIDELINES AND STANDARDS CONSTITUTING THE BIG RIVERS OPERATING PROCEDURES AND GUIDELINES

(To be Jointly Developed by Big Rivers and HMP&L after Agreement Execution)

Attachment E

OPERATING PROTOCOLS

(To be Jointly Developed by Big Rivers and HMP&L after Agreement Execution)

Brad Bickett

From:	naultytp1@gmail.com
Sent:	Tuesday, December 4, 2018 12:49 PM
To:	Brad Bickett
Cc:	Joella Wilson
Subject:	FW: Clarifications to HMP&L RFP for TOP and LBA Services
Attachments:	UB 18-11-14 LBA and TOP_HMPL RFP_Gridforce Proposal_113018_Addendum.pdf

Clarifying information from Gridforce.

From: Huston, Frank <Frank.Huston@NAES.com>
Sent: Tuesday, December 4, 2018 12:58 PM
To: naultytp1@gmail.com
Cc: Ingersoll, CJ <CJ.Ingersoll@grid4ce.net>; Ayers, Denise <Denise.Ayers@grid4ce.net>; Bull, Alan <Alan.Bull@naes.com>
Subject: RE: Clarifications to HMP&L RFP for TOP and LBA Services

Terry,

For CJ, I am forwarding this attached letter that includes a table as you requested showing the compliance history for Gridforce.

We are happy to provide additional information at any time.

Kind regards,
Frank

From: naultytp1@gmail.com <naultytp1@gmail.com>
Sent: Monday, December 3, 2018 9:04 AM
To: Ingersoll, CJ <CJ.Ingersoll@grid4ce.net>
Cc: Ayers, Denise <Denise.Ayers@grid4ce.net>; Huston, Frank <Frank.Huston@NAES.com>
Subject: RE: Clarifications to HMP&L RFP for TOP and LBA Services

WARNING: This email originated from outside of NAES

CJ,
In my initial review of your proposal I did not see any documentation of your firm's compliance history with NERC requirements. This is one of the proposal evaluation criteria that was identified in the RFP.

- *NERC compliance record- bidder shall provide a summary of the results of any NERC or reliability organization's (SERC, RFC, etc.) audits completed in the last 36 months.*

Can you please provide at least the following information:

Compliance History

Audit Year	Entity performing Audit	Function	Possible Violations	Find Fix Track	Areas of Concern	Recommendations	Positive Observations

2015	RFC, SERC, WECC, etc.	LBA, TOP, etc.					
2016							
2017							

Please don't hesitate to call me if you have any questions or require clarification.

Regards,
Terry Naulty
Principal
Naulty Energy Consulting & Advisory LLC
812-972-1457

Proposal for

Transmission Operator (TOP) and Local Balancing Authority (LBA) Services

1.0 Purpose

This document is a proposal from Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier) to provide Transmission Operator (TOP) Services to Henderson Municipal Power & Light (HMP&L) in response to their request for proposal on 11-14-18.

In regard to providing Local Balancing Authority (LBA) services, this proposal:

- includes those items necessary to comply with the appropriate NERC standards
- and does not include any LBA activity from a MISO market prospective,
- and establishes HMP&L loads as a stand alone LBA and not incorporated into the Hoosier LBA in Indiana or Illinois.

2.0 Summary of Proposal

Hoosier proposes to provide such services under the following structure:

a. Annual Fees paid by HMP&L.

2019	2020	2021
$627,600.00	$643,200.00	$658,800.00

Annual Fees will be paid monthly as shown below.

2019	2020	2021
$52,300.00	$53,600.00	$54,900.00

Please see details of the services provided under this annual fee in sections 4.0 below.

b. HMP&L will reimburse Hoosier for any costs needed to fulfill TOP and BA services. This will include initial work required to update Hoosier EMS databases, Network Models updates, and application checkouts to allow for the monitoring, analysis, and logging required to provide TOP and LBA services. Ongoing fees such as but not limited to, communications links, additional licensing fees, and hardware necessary to supply services to HMP&L will also be reimbursed.

Please see more detailed of reimbursable items that Hoosier has identified as necessary to provide services to HMP&L in sections 5.0 below.

3.0 Qualifications of Hoosier

Hoosier owns and operates a primary and backup control centers currently NERC certified by Reliability First.

Hoosier has worked as a team with Reliability First developing a robust culture of compliance throughout Hoosier that has led to excellent audit results. Results over the last 6 years (72 months) since 2012 are shown in the following table.

Audit Year	Possible Violations	Find Fix Track	Areas of Concern	Recommendations	Positive Observations
2012 Reliably Audit (693)	0	0	2	NA in 2012	0
2013 Critical Infrastructure Protection (CIP) Audit	0	2	3	16	5
2015 Reliably Audit (693)	0	0	2	8	1
2016 Critical Infrastructure Protection (CIP) Audit	0	0	2	26	6
2018 Reliably Audit (693)	0	0	0	4	3

Please note that Hoosier encourages audit teams to provide recommendations where Hoosier follows through with implementing such recommendations thoroughly in an effort to

- improve culture of compliance,
- improve reliability to Hoosiers member system customers,
- and improve reliability of the Bulk Electric System.

Hoosier has become a leader in the development of internal controls as noted in the recent Reliability First newsletter (see page 11, 12 attached). Recent trends show regions such as Reliability First and SERC are moving beyond traditional compliance and beginning to evaluate entities, such a Hoosier, internal controls and control environments. Evaluating and entities internal controls is becoming part of the audit process.

Hoosier's compliance department includes a Manager, Compliance, NERC and Power Markets, a CIP Compliance Coordinator and a Compliance Specialist.

In an effort continually to improve, Hoosier has become a leader in the North American Transmission Forum participating in:

- a comprehensive Peer Review of Hoosier Energy in 2017,
- the Reliability Metrics Team in the Metrics Working Group,

- the Cost Metrics Team,
- the Compliance Practices group with risk assessment and internal controls.

Hoosier is registered with NERC (#NCR00794) within the Reliability First Corporation (RF) footprint as a:

Balancing Authority (BA)	Distribution Provider (DP)
Generator Owner (GO)	Generator Operator (GOP)
Transmission Owner (TO)	Transmission Operator (TOP)
Transmission Planner (TP)	Resource Planner (RP)

Hoosier is registered with NERC (#NCR00794) within the Southeastern Reliability Corporation (SERC) region as a Distribution Provider (DP).

MISO provides Hoosier with Reliability Coordinator (RC) and Balancing Authority (BA) services where Hoosier is a Local Balancing Authority (LBA) within the MISO BA Area under a CFR agreement.

MISO is also Hoosier's Planning Authority (PA) and Transmission Service Provider (TP). Hoosier is a member of Mid-Contentment Independent System Operator (MISO) and participates in the MISO Energy Markets.

Hoosier Energy is a non-profit Generation and Transmission Cooperative providing wholesale electric power and services to 17 member distribution cooperatives in central and southern Indiana and one in southeastern Illinois. Hoosier's member aggregate peak system load is 1698 MW set in January 2014. Hoosier's LBA peak in January 2014 was 738.4 MW where the rest of Hoosier load was served by other BA/LBA's where Hoosier manages all interactions between Hoosier's member DPs and the other TOPs and BA/LBAs.

Based in Bloomington, Indiana, Hoosier operates coal, natural gas, and renewable energy power plants, owning approximately 1426 MW of generation in the ReliabilityFirst footprint. Hoosier delivers power through its 318 miles of 345 kV, 161 kV and 138 kV Bulk Electric System (BES) transmission lines and over 1,300 miles of 69 kV lines. Hoosier interconnects with the following neighboring transmission owners:

1. Duke Energy Indiana,
2. Vectren
3. Big Rivers
4. Indianapolis Power & Light Company

4.0 Details about Annual Fees

TOP and BA Services for HMP&L's Bulk Electric System (161 kV)

Hoosier will perform all necessary activities in an effort to thoroughly comply with NERC Reliability Standard requirements on behalf of HMP&L that are applicable to the Transmission Operator and Balancing Authority functions except for the CIP standards that include both TO and TOP functions.

This proposal includes that HMP&L will be responsible for complying with all CIP standards since there should not be any medium or high impact facilities at HMP&L. This will require a delegation agreement because of the TOP and TO applicability of the CIP standards. Examples of TOP and LBA services needed to thoroughly comply with NERC standards for 161 kV facilities under the Annual Fees are listed below.

- Directing the operation of HMP&L Bulk Electric System (BES) which includes all 161 kV equipment in regard to the TOP and BA functions.
- Monitoring HMP&L 161 kV system for pre and post contingent System Operating Limits (SOLs) exceedances and working with MISO to coordinate and implement corrective actions plans. SOLs include both thermal and voltage exceedances. Pre contingent means using the state estimator computer modeling to simulate outages on the BES including outages on neighboring systems. Post contingent means real time thermal and voltage exceedances.
- Reviewing Next Day Studies and Current day studies as required by the TOP standard. This includes documenting corrective action plans that may be needed to mitigate voltage and thermal SOL exceedances.
- Ensuring that there are Operating Plan(s) for next-day operations to address potential SOL exceedances identified as a result of its Operational Planning Analysis. This includes voltage and thermal pre and post contingent SOL exceedances.
- Ensuring Real-time Assessments are performed at least once every 30 minutes.
- Confirmation that state estimator is solving 24/7/365.
- Initiate any Operating Plans to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessments.
- Monitor Facilities within HMP&L's TOP area and obtain and utilize status, voltages and flow data outside of HMP&L's TOP area.

- Monitor necessary Low Voltage Facilities within HMP&L's TOP area and obtain and utilize status, Low voltages and flow data outside of HMP&L's TOP area that could impact the BES SOL's.

- Communicate any HMP&L 69kV facilities limit violations with HMP&L personnel, work with HMP&L to develop mitigation plan and interface with MISO and Big Rivers on behalf of HMP&L to mitigate those limit violations.

- Ensuring Operating Instructions from the MISO RC are followed. Review logs to confirm where there were no Operating Instructions (this is needed for audit purposes).

- Ensure Operating Instructions are issued by the TOP when needed.

- Informing the MISO RC with inability to perform an Operating Instruction when needed.

- Coordinate actions needed to mitigate SOL exceedances with neighboring TOPs.

- Coordinate Outages between MISO and BREC.

- Enter 161 kV outages in CROW and get approval.

- Enter 69 kV outages in CROW

- Review outage requests.

- Develop and provide training for HMP&L staff (such as 3 part communication).

- Add HMP&L to the Reliability portal to use when MISO issues power emergencies.

- Integrate HMP&L into Emergency and Operations plans as necessary for TOP and LBA functional requirements.

- Maintain existing Emergency and Operations plans.

- System Control staff dedicated to monitoring HMP&L System 24/7/365.

- Ongoing review of new TOP and BA standard applicability, RSAW drafts and audit preparation, complete three year regional audits.

- Coordinate with the BA Committee for the MISO CFR.

- Hoosier maintains a comprehensive evidence Matrix and calendar event processes to ensure Subject Matter Experts complete tasks on time and evidence is collected and filed in a timely manner.

- Hoosier uses other processes to assess detective, preventative and corrective internal controls ensure to reduce the change that a violations will be identified at audit, and any possible issues will be identified and self reported to the regional entity.

5.0 Details about Reimbursable Costs

If Hoosier's proposal is accepted, HMP&L will agree to reimburse Hoosier for reimbursable costs needed to adequately fulfil Hoosier's obligation to provide BA and TOP services and thoroughly comply with NERC standards. Details of reimbursable costs will be negotiated in a subsequent contract.

Examples of reimbursable costs are listed below:

- New hardware for ICCP connections to monitor HMP&L substation; the equipment will be owned by HMP&L and Hoosier may assist in obtaining equipment for HMP&L as a reimbursable cost,

- Expand the State Estimator computer model to include HMP&L and their neighbors portion of the BES,

- Develop training for operators in coordination with Hoosier procedures if necessary,

- Add HMP&L to Hoosier's Capacity Emergency Portal,

- Develop appropriate operational one line diagram of their system,

- Expand map-board to include HMP&L system,

- Develop EMS one line display of the HMP&L system,

- Re-certification of Hoosier's System Control Center with the addition of HMP&L facilities.

6.0 Contract Negotiations

This proposal is not a binding agreement, and no binding agreement of any kind shall exist between Hoosier and HMP&L unless and until all necessary approvals and consents are obtained and definitive agreements for the Proposal are executed and delivered by both Parties. Notwithstanding anything to the contrary in this bid, the execution, delivery and performance of this proposal shall not require the Parties or any of their respective affiliates to consummate any commercial relationship or enter into any definitive agreement with respect thereto. The consummation of the transaction summarized in this proposal will be subject to the ultimate negotiation and execution of a definitive agreement among the parties. Further, nothing herein shall be construed to obligate either party to enter into any further agreement regarding the subject matter hereof. Any actions taken by either party in reliance on the non-binding terms expressed in this proposal or on statements made during negotiations pursuant to this proposal shall be at that party's own risk, and this proposal shall not be the basis for a contract by estoppel, implied contract or any other legal theory.

Attachment 1 – Bid Clarification and/or Exceptions Form

BID CLARIFICATIONS AND/OR EXCEPTIONS
UB #18-11-14

7.0 Confidentiality

Confidentiality. Hoosier and HMP&L agree that during the term of the proposal and for a period of three (3) years thereafter, neither party shall, without the prior written consent of the other party, disclose to any third party (other than the receiving party's Affiliates who have a need to know) the terms and conditions of this proposal or any non-public information provided in connection with this proposal.

Permissible Disclosures. Notwithstanding the above, a party may disclose confidential information of the other party as required by Applicable Law or under order of a court or government agency of competent jurisdiction; provided, however, that the receiving party shall, if permitted by Applicable Law, promptly give written notice of the disclosure to the disclosing party prior to the date of disclosure. Further, notwithstanding the above, a party may disclose confidential information of the other party to any third party who has a reason to know in connection with a potential acquisition of the receiving party or any of its assets, provided that such third party is bound by a confidentiality agreement protecting such information on terms consistent with those set forth in this Agreement.

8.0 Approval

Hoosier Energy Rural Electric Cooperative, Inc.

Signature:________________________

By: David W. Sandefur

Title: Vice President, Operations

Attachment 1 – Bid Clarification and/or Exceptions Form
BID CLARIFICATIONS AND/OR EXCEPTIONS
UB #18-11-14

Bidder offers the following clarifications and/or exceptions taken to any requirement or provision of this Invitation to Bid and any proposed modifications or replacement language for each clarification or exception. (If none, so state.)

Contract issues must be mutually negotiated in a definitive contract between Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier) and Henderson Municipal Power & Light (HMP&L). At anytime during negotiations and up to the execution of a definitive contract either party can choose to not execute the contract and terminate any negotiations with no penalty for not executing the contract.

The following will be negotiated in the contract:

- A proposed schedule for integration of ICCP meter telemetry, training, communication protocol development with HMP&L and MISO who will be the Reliability Coordinator (RC) for HMP&L.

- Contract extension terms for each renewal beyond the Initial term.

Clarifications / exceptions will be addressed in the contract.

Clarifications/exceptions:

- Hoosier did not complete the "REQUIRED AFFIDAVIT FOR BIDDERS, OFFERORS AND CONTRACTORS CLAIMING RESIDENT BIDDER STATUS" document because item 2 does not apply to Hoosier.
- Hoosier has the right to inspect the condition of all HMP&L facilities.
- Contract will be contingent on Hoosier Energy Board of Director approval.
- Any Contract extension terms for any renewal beyond the Initial term must be mutually agreeable.
- Bid is contingent on acceptable development of Hoosier/HMP&L TOP & LBA Operating Protocol Procedure.
- Contract will be contingent on Hoosier Energy's successful application/registration as TOP and BA within the SERC region and Certification of Hoosier Control Centers by SERC.
- Contract will be contingent on the successful setup and implementation of HMP&L loads being established within a HMP&L LBA in the MISO construct. Hoosier will not incorporate HMP&L's loads into the Hoosier LBA.
- HMP&L will reimburse any and all associated cost of establishment of the HMP&L LBA with MISO or MISO Market.

- Bid is subject to acceptance of an implementation date of no earlier than June 1st, 2019
- HMP&L warrants the validity of operational information provided by HMP&L due to facility ratings, equipment/facility impedance modeling data, or scaling factors of data necessary to be obtained from HMP&L to provide requested TOP and BA functions and Hoosier accepts no liability for any inaccuracy in such information.
- Hoosier accepts no responsibility for any other NERC or SERC Reliability Standards Requirements applicable to any other registration of HMP&L or any registrations that may be applicable to HMP&L or any other Federal, State, or Local Governmental regulations, ordinances, or laws not outlined in this bid proposal.
- Hoosier accepts no liability for defects, issues or problems with HMP&L ownership, maintenance, construction, engineering, or design work or practices of any of HMP&L's physical transmission, sub-transmission or distribution facilities.
- HMP&L operating and line staff must complete training required by Hoosier, including but not limited to Hoosier Switching procedures, complying with NERC standards which mostly includes 3 part communication with Hoosier System Control Operating staff, etc.
- HMP&L staff must provide line facility rating and impedance modeling data necessary for the monitoring, modeling, and assessment of the HMP&L system within 10 business days of Bid acceptance by HMP&L.
- HMP&L must provide Hoosier access to its operational logs, as of contract implementation, to support Standard Requirement/evidence tracking.
- Hoosier will not be responsible for any NERC Standard Requirements prior to the implementation date of the contract.
- As the CIP Standards are applicable to TO and TOP; HMP&L will agree to a delegation agreement to comply with all CIP standards associated with HMP&L Substations, SCADA, or Operations/control center equipment on behalf of the TOP or BA obligation.
- HMP&L will be responsible for any assessed penalties of TOP or BA NERC Standard Violations that result from misinformation, unfulfilled requested for information or data, or failure of HMP&L staff to perform Operating Instructions or Emergency Operating Instructions issued by the TOP or BA.
- Terms for payments and late payment fees will be specified in contract negotiations.
- Cost of early termination of the contract will be established during contract negotiations.
- Hoosier will supply functional (TOP standard) control over the HMP&L BES System only and HMP&L will be responsible for all detailed isolation clearance procedure for protection of HMP&L personnel or agents working on HMP&L facilities. Functional Control only covers Interface with MISO and MISO systems and Issuing of Operating Instruction to HMP&L Dispatch Center Personnel.
- HMP&L will be responsible for providing Hoosier equipment Clearance or Isolation Holds on HMP&L equipment as needed for neighboring TOP entities outage requests. Hoosier will provide the interface activities with the neighboring TOP entities.
- HMP&L must provide Hoosier with a copy of their Safety/Lockout/Tagout Procedure.

- As the Distribution Provider and Transmission Owner, HMP&L must provide a separate letter of Authority for Hoosier System Control Operators to take any and all steps necessary to maintain reliability of the HMP&L and neighboring BES facilities up to and including shedding load. This letter must be signed by appropriate level of management.

Confidentiality

Confidentiality. Hoosier and HMP&L agree that during the term of the proposal and for a period of three (3) years thereafter, neither party shall, without the prior written consent of the other party, disclose to any third party (other than the receiving party's Affiliates who have a need to know) the terms and conditions of this proposal or any non-public information provided in connection with this proposal.

Permissible Disclosures. Notwithstanding the above, a party may disclose confidential information of the other party as required by Applicable Law or under order of a court or government agency of competent jurisdiction; provided, however, that the receiving party shall, if permitted by Applicable Law, promptly give written notice of the disclosure to the disclosing party prior to the date of disclosure. Further, notwithstanding the above, a party may disclose confidential information of the other party to any third party who has a reason to know in connection with a potential acquisition of the receiving party or any of its assets, provided that such third party is bound by a confidentiality agreement protecting such information on terms consistent with those set forth in this Agreement.

Bidder understands that unless itemized above, no other clarifications or exceptions to this Invitation to Bid are taken by this Bidder.

Signature

Hoosier Energy Rural Electric Cooperative, Inc.
David W. Sandefur
Vice President, Operations

Signature of Executing Party

HMP&L

Attachment 2 – Reciprocal Preference Form

Bid #: 18-11-14

RECIPROCAL PREFERENCE: (Effective February 4, 2011)

In accordance with Kentucky Revised Statutes (KRS) 45A.490 to 45A.494, prior to a contract being awarded to a bidder on a public agency contract, a resident bidder of the Commonwealth of Kentucky shall be given a preference over a nonresident bidder registered in any state that gives or requires a preference over bidders from the other state. The preference shall be equal to the preference given or required by the state of the nonresident bidder.

Any individual, partnership, association, corporation, or other business entity claiming resident bidder status shall submit along with its bid response a notarized affidavit (form attached) that affirms that it meets the criteria to be considered a resident bidder as set forth in KRS 45A.494(2). A nonresident bidder shall submit to HMPL, along with its bid response, a copy of its Certificate of Authority to transact business in the Commonwealth of Kentucky as filed with the Kentucky, Secretary of State. The location of the principal office identified therein shall be deemed the state of residency for that bidder. If the bidder is not required by law to obtain said Certificate, the state of residency for that bidder shall be deemed to be that which is identified in its mailing address as provided in its bid.

Bidders must select and check one option below and return this document with bid.

☐ This company is a resident bidder of the Commonwealth of Kentucky **or** this company is a nonresident bidder meeting the following requirements:

1. Is authorized to transact business in the Commonwealth; and
2. Has for one year prior to and through the date of advertisement
   a. Filed Kentucky corporate income taxes; and
   b. Made payments to the Kentucky unemployment insurance fund established in KRS 341.49; and
   c. Maintained a Kentucky workers' compensation policy in effect.

The Required Affidavit for Bidders, Offerors and Contractors Claiming Resident Bidder Status form attached must be completed and returned with bid.

☒ This company is not a resident bidder nor does it meet the requirements as listed in Items 1 and 2 above for nonresident bidders claiming resident status in the Commonwealth.

What is your state of residency? Indiana

Does your state grant "Contract Bid Preference? (circle one) No / Yes

What is the Preference Percentage for your state? ________ %

Hoosier Energy REC, Inc.
Company

November 30, 2018
Date

[signature]
Signature

David W. Sandefur
Printed Name

Attachment 4 - Notice of Intent to Bid Form

Name of Bidder Hoosier Energy Rural Electric Cooperative, Inc.

Company Representative David W. Sandefur

Representative Title Vice President, Operations

Representative Contact Information
Email Address: Dsandefur@hepn.com
Office Phone Number: 812-876-0347
Mobile Phone Number 812-322-0630

Expected Proposal (Check as Appropriate)
___ Local Balancing Authority Service
___ Transmission Operator Service
_X_ Local Balancing Authority and Transmission Operator Services

Please send completed form to:
Terry Naulty
Principal, Naulty Energy Consulting and Advisory LLC
Naultytp1@gmail.com

HMP&L Henderson Municipal Power & Light

Attachment 6 – Nondisclosure Agreement

CONFIDENTIAL INFORMATION NON-DISCLOSURE AGREEMENT

This NON-DISCLOSURE AGREEMENT is made by the undersigned ("Vendor") and Henderson Municipal Power & Light ("HMP&L"), with its primary address located at 100 5th street, Henderson, Kentucky 42420.

The Vendor has requested that HMP&L disclose to the Vendor certain information, all or a portion of which may be classified by HMP&L as Bulk Electric System Cyber System Information (BCSI); and

The North American Electric Reliability Corporation Critical Infrastructure Protection Standards (NERC CIP), has defined BCSI as "information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems;" and,

The Vendor is working on *Transmission Operator (TOP) and Local Balancing Authority (LBA) Services* requiring access to certain information classified as BCSI.

For purposes of this Agreement, "BCSI" shall mean: (i) all information designated as such by HMP&L, whether furnished before or after the date hereof, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished; and (ii) all reports, summaries, compilations, analyses, notes or other information which contain such information. Written information containing BCSI furnished by HMP&L shall be considered classified information and labeled "**Confidential BCSI**".

Information labeled "**Confidential BCSI**" shall be kept in a secure place. The Vendor shall exercise reasonable care to maintain the confidentiality and secrecy of the classified information, and shall not divulge classified information to any third party without the prior written consent of HMP&L. The Vendor shall use all classified information disclosed by HMP&L only for the referenced work above.

AGREED (Vendor):

Hoosier Energy Rural Electric Cooperative, Inc.
David W. Sandefur
Vice President, Operations

DW Sandefur

Signature

RFP - TOP & LBA Services
UB - #18-11-14

Operating Protocols Between
MISO Reliability Coordinator &
Transmission Operators
Addendum 1
RFP TOP & LBA Services

Vendor List

Attachment 4 – Notice of
Intent to Bid Form

Advertisement

Vendor Sign In Sheet
UB 18-11-14

Hoosier Energy Rural
Electric Cooperative, Inc

Gridforce

Big Rivers Electric
Corporation (BREC)

RFP - TOP & LBA Services
UB - #18-11-14

Operating Protocols Between
MISO Reliability Coordinator &
Transmission Operators
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Vendor List

Attachment 4 – Notice of
Intent to Bid Form

Advertisement

Vendor Sign In Sheet
UB 18-11-14

Hoosier Energy Rural
Electric Cooperative, Inc

Gridforce

Big Rivers Electric
Corporation (BREC)

COMMISSION MEMO

TO: Chris Heimgartner, General Manager

FROM: Brad Bickett, Reliability Compliance Manager BB

DATE: December 1, 2018

RE: Transmission Operator (TOP) and Local Balancing Authority (LBA) Services Three (3) Year Agreement with two one-year extension options for maximum of five (5) years.

ACTION REQUESTED

Commission approval to provide a Three (3) Year Local Balancing Authority and Transmission Operator Services Agreement with Fourth and Fifth Year Renewal Options.

BACKGROUND

On November 30, 2018, the City of Henderson Utility Commission received sealed bids for comprehensive services that will fulfill all NERC and SERC requirements applicable to the functions of Transmission Operator and Local Balancing Authority, while following any MISO business practices that may be in effect while providing such services.

Beginning February 1, 2019, HMP&L's Station Two, consisting of 312 MW of coal fired generation will be retired (approved by MISO) and HMP&L will become a non-generating municipal utility. Under the current contracts, Big Rivers Electric Corporation (BREC) operates Station Two and provides TOP and BA services to HMP&L as part of those contracts.

BREC has proposed that it will no longer be providing TOP and LBA services to HMP&L after January 31, 2019. HMP&L is in the process of registering with MISO as a Market Participant (MP), Load Serving Entity (LSE) and Transmission Owner (TO). HMP&L is also currently evaluating new power supply contracts that will be effective on June 1, 2019.

EVALUATION

HMP&L distributed seven (7) Requests for Proposals to provide TOP and LBA services. Three (3) responsive bids were received: Hoosier Energy Rural Electric Cooperative, Inc., Gridforce Energy Management, and Big Rivers Electric Corporation. The Big Rivers proposal was deemed non-responsive as it did not meet the minimum term requirement of 3 years. Gridforce Energy Management was the best evaluated bid that came closest to meeting the Specification.

RECOMMENDATION / MOTION

Motion to provide a Three (3) Year TOP/LBA Agreement with Fourth and Fifth Year Renewal Options for the supply of reliability services in the amount of $600,000 per year for the first year, with one-time implementation costs of $215,400, and annual site maintenance in the amount of $10,000, to Gridforce Energy Management for HMP&L, and to authorize the HMP&L staff to complete negotiations of the terms and conditions for a mutually acceptable Local Balancing Authority and Transmission Operator Services Agreement.

Naulty Energy Consulting and Advisory LLC

Each of the following sections of the evaluation provide my assessment for the five criteria.

1. Experience Providing TOP and LBA Services

1.1. Gridforce Energy Management

Proposer Qualifications	Comments
41 separate balancing areas managed since inception of company	Unmatched expereince in setting up and operating BAs as a third party. Understand commercial risks and have tested service contract.
No active LBA contracts in MISO - thus no potential conflicts of interest	From list of customers, no LSEs in MISO which will require some time to develop the required protocols and establish contacts with MISO technical personnel.
6 separate municipal entities in SERC, 1 in ERCOT	While municipal customers are no longer being serviced by Gridforce, staff understands the communication challenges of a remote provider of BA services.
3 TOP functions for merchant generators	While experience is limited to generators, the substation configurations and amount of BES equipment is very similar to HMP&L subs and equipment.
2 in PJM, 1 in WECC	Not registered as TOP or BA with SERC and has no experience as TOP with MISO as RC, but experience with PJM, a very similar RTO from a transmission and RC operating perspective.
	Will require registration in SERC as TOP

1.2. Hoosier Energy

Proposer Qualifications	Comments
Manages load for 17 member distribution cooperatives - all in MISO	Clearly understand the scope of work for LBA and would effectively look at Henderson as a "new member" from a service perspective. Work for HMPL is a subset of what they provide for member coops because it will not include energy settlement functions and those activities of an MDMA.
	Because Hoosier would not be settling energy or ancillaries, there will be no commerical conflicts. Any concerns regarding optimization of HMP&L transmission system to minimize congestion charges to members will need to be delt with in services agreement.
	No expereince working with Municipal utilities or third party LBAs - establishing procedures and relationships with HMP&L operations personnel will be a new activity for Hoosier.
Currently registered as TOP with RFC.	Has all necessary systems and protocols in place and understands the relationship between MISO and TOPs. Bob Solomon was a driving force behind the establishment of the MISO Operating Protocol between MISO as RC and TOPs.
	Not registered as BA or TOP and has no direct SERC experience as TOP, but reliability standards are the same for all ERO's
	Will require registration in SERC as TOP

2. **Compliance History**

2.1. **Gridforce Energy Management**

Proposer Qualifications	Comments
Since 2016, 3 potential violations, both CIP related	HMP&L has no CIP equipment. However, potential violations are cause for concern since they may be indicative of shortcomings in compliance documentation and/or abitlity to stay current on best practices.

2.2. **Hoosier Energy**

Proposer Qualifications	Comments
No audit findings back through 2012, 2 areas of concern in last reliability organization audit	last three reliability audit have had no violations and only the last one only had 4 recommendations.

3. **Price**

3.1. **Gridforce Energy Management** – Proposal calls for a monthly service fee and a monthly equipment fee. Both are subject to annual escalation based upon the published Consumer Price Index (CPI). All setup costs are on a pass-through basis with the proposer providing a list of applicable equipment cost.

3.2. **Hoosier Energy** – Proposal calls for a single monthly fee for the first three years. Escalation is computed at 2.5% per year and that assumption is continue for years 4 and 5. All setup costs are on a pass-through basis, but no costs were provided for specific equipment.

Comparative Costs

	Gridforce		Hoosier Energy
	currentl cpi	High cpi	Annual Fee
CPI	0.025	0.028	n/a
Year	Annual Fee	Annual Fee	Annual Fee
1	$ 610,000.00	$ 610,000.00	$ 627,000.00
2	$ 625,250.00	$ 627,080.00	$ 643,200.00
3	$ 640,881.25	$ 644,638.24	$ 658,800.00
4	$ 656,903.28	$ 662,688.11	$ 675,299.99
5	$ 673,325.86	$ 681,243.38	$ 692,213.24
Total FV	$ 3,206,360.39	$ 3,225,649.73	$ 3,296,513.23
NPV	$2,849,306.79	$2,865,791.19	$ 2,929,428.06

4. **Project Manager/Staff Qualifications**

4.1. **Gridforce Energy Management**

Proposer Qualifications	Comments
Denise Ayers Project Manager - very experienced in all aspects of setting up and operating BAs and limited TOP	Proposal showed significnat insight into understanding of the timing an how the service agreement would be executed. Project manager and team have implemented many assignments of this nature and understand fully the mechanics of how to accomplish what needs to be done as quickly as possible.
Expereinced staff to support all aspects of service	Staff has a customer focus and 24 hour desk personnel are expereinced in dealing with multiple RTOs on BA and TOP issues.

4.2. Hoosier Energy

Proposer Qualifications	Comments
Bob Solomon, Hoosier's Manager of Compliance, NERC and Power Markets is the proposed project manager. He is very active with MISO.	Clearly the proposed project manager understands the scope of work. However, implementing these services as a third party provider represents a new challenge.
Staff includes the former manager of Transmission Control Center with Duke, and thus knows how to interact with MISO as RC and other TOPs.	24-hour staff and functional leads are extremely qualiifed but will required training. Dealing with HMP&L as a "customer" for services that the staff provides to its internal clients is also a new venture for Hoosier.

5. **Transition Management** – The uncertainty surrounding the termination of services currently being performed by Big Rivers has become more important than when the RFP was issued. This is due to the presence of more facts about Big River's intent and better awareness of the integration time that will be required to fully comply with NERC requirements.

5.1. Gridforce Energy Management

Proposer Qualifications	Comments
Have basics in place by Feb 1. Full implemetation by May 1.	Proposes to use existing ICCP and quick access to SCADA to gain access to data and provide real time monitoring. Aggressive time table but one that understands the scense of urgency. Third party provider structure prioritizes getting systems up and running to meet customer expectations.

5.2. Hoosier Energy

Proposer Qualifications	Comments
Proposed schedule would achieve full standup of service on June 1, 2019	No granularity of implementation schedule provided in proposal. Could be indicative of additional time required to map out the schedule of implementation and the potential to miss the critical path schedule. Proposes to use exisitng staff who are supporting NERC functions for the TO and LSE functions.

HMP&L

December 7, 2018

Chris Heimgartner, General Manager
City of Henderson, Utility Commission
P O Box 8
Henderson, KY 42420

RE: UB 18-11-14 – Transmission Operator (TOP) and Local Balancing Authority (LBA) Services

Dear Sir:

Copies of all bids received have been submitted for your review. Bids were solicited from seven (7) bidders. Bids were received from:

1. Gridforce Energy Management
2. Hoosier Energy
3. Big Rivers Electric Corporation

Gridforce was the lowest and best evaluated bid that came closest to meeting the Specification. We would respectfully ask that the Commission accept Gridforce Energy Management as the successful bidder.

Sincerely,

Brad Bickett
Reliability Compliance Manager

GRIDFORCE

Local Balancing Authority (LBA) and Transmission Operator (TOP) Services UB #18-11-14 RFP

FOR THE

City of Henderson, Kentucky Utility Commission (HMP&L)

HMP&L

November 30, 2018

GRIDFORCE

4 Houston Center
1331 Lamar Street, Suite 560
Houston, Texas 77010

November 30, 2018

Mrs. Joella Wilson
City of Henderson, Kentucky, Utility Commission
DBA/Henderson Municipal Power & Light
100 Fifth Street
Henderson, KY 42420

Via Email: rfp@hmpl.net

Subject: UB #18-11-14 LBA and TOP Services RFP

Dear Mrs. Wilson,

In response to the RFP UB #18-11-14, Gridforce Energy Management, LLC (Gridforce) is pleased to submit its proposal to the City of Henderson, Kentucky, Utility Commission (DBA/Henderson Municipal Power & Light [HMP&L]) to provide Local Balancing Authority (LBA) and Transmission Operator (TOP) Services to the City of Henderson. HMP&L's system consists of the following: four (4) 69 kV Tie Lines; two (2) 161 kV Tie Lines adjacent to BREC; 34.86 miles of 69 kV distribution line; 22 miles of 161 kV transmission line; one (1) 161 kV substation; and, six (6) 69 kV substations.

We appreciate the opportunity to work with HMP&L and play a key role its transition in the coming years. We have reviewed the RFP document to carefully gain an understanding of HMP&L's needs and have worked hard to craft a responsive proposal.

Gridforce will:

- Leverage over twenty years of Balancing Authority experience to successfully implement any required Local Balancing Authority functions coordinated with MISO and interconnected Local Balancing Authorities.
- Employ the Gridforce control center and backup control center infrastructure, including redundant data centers in geographically disperse areas that is currently utilized to perform Balancing Authority and Transmission Operator services for Bulk Electric Systems.
- Utilize highly qualified NERC Certified System Operators who staff our 24/7 control center at all times to monitor equipment status and limits, coordinate outages, implement Lock-Out / Tag-Out procedures, perform system assessments and implement emergency procedures.

Gridforce is driven by its mission to deliver the best outcomes for HMP&L and reliable system operations. We offer numerous experiences to support this mission:

- Concentration on Bulk Electric System reliability services and no marketing function roles.
- Extensive experience in data collection from metering and substation station devices for system

operators to perform Bulk Electric System reliability services.

- Existing and audit proven procedures addressing hourly meter verification, emergency conditions and Event Reporting, loss of primary control center functionality, and a systematic approach to training.
- Experience in working with MISO and SERC to maintain reliability and compliance with applicable regulations. Gridforce is working with a municipal utility in Illinois and has been awarded work with three other municipal utilities in Ohio to provide TOP services similar to the scope requirements for HMP&L. We will transfer the experiences from these projects directly over to HMP&L.
- In-depth technical resources and home office support in accounting and operational programs.
- No conflicts of interest at any level.
- Fixed fee services structure.

We trust that you will find this information responsive to your RFP. We look forward to the opportunity to provide LBA and TOP services to your organization. If you have any questions regarding this proposal, please contact me at 713.332.2906 (office) or at 832.477.8696 (mobile).

Sincerely,

CJ Ingersoll
President, Gridforce Energy Management

cc: Jason Fournier, Vice President, Energy Solutions, NAES
Alan Bull, General Manager, Energy Solutions, NAES
Pat Ombrellaro, General Manager, Sales Operations, NAES

TABLE OF CONTENTS
Proposal for the City of Henderson, Kentucky, Utility Commission (dba HMP&L)
UB #18-11-14 LBA and TOP Services RFP

Section 1.0: Gridforce Response to RFP

In accordance with HMP&L's Request for Proposal (RFP), Gridforce provides below a point-by-point cross reference table showing the HMP&L's RFP requirement and the Gridforce proposal section where the RFP requirement is to be found.

HMP&L TOP and BA Services	
Proposal Requirement	**Proposal Section**
1. Qualification of the bidder to provide proposed services, including, but not limited to the names of BA, LBA, or TOP customers or balancing areas/transmission systems for which bidder is providing or has provided service to, and how long bidder has been providing applicable services.	2.3
2. NERC compliance record- bidder shall provide a summary of the results of any NERC or reliability organization's (SERC, RFC, etc.) audits completed in the last 36 months.	2.1
3. Proposed staff, including an identified Project Manager, and their qualifications/certifications and organization chart detailing functional responsibility for the applicable NERC requirements.	2.4
4. A description of the recordkeeping and tracking systems used by the bidder to document compliance with applicable NERC/SERC or RTO standards/work practices, reporting and recordkeeping protocols.	3.2, 3.3
5. A proposed schedule for integration of ICCP meter telemetry, training, communication protocol development with HMP&L and MISO who will be the Reliability Coordinator (RC) for HMP&L.	3.2
6. Contract extension terms for each renewal beyond the Initial term.	4.1
7. Price proposal which shall specify the following:	
7.1 Annual service fee and any applicable annual escalations;	4.1
7.2 Configuration/mobilization/testing costs that are one-time costs for establishing the required telecommunications systems for meter data and communications with MISO and HMP&L; and	4.1
7.3 Any and all other costs proposed by bidder.	-
8. Proposed Services Contract or a Binding Term sheet with the key terms and conditions detailed. HMP&L reserves the right to negotiate terms and conditions of the service contract with the successful bidder.	5.0
9. Start date for services if not February 1, 2019.	3.2
10. Completed Bid Clarifications and Exceptions Form (Attachment 1) – include any items in the specification of the RFP that bidder will not comply with or will exclude from its provision of services.	6.0
11. Completed Reciprocal Preference Forms 1 and 2 (Attachment 2)	7.0
12. Non-Disclosure Agreement (Attachment 6)	8.0
13. Addendum 1 – Revised Scope of Work and the addition of Attachment 7	10.0
14. Attachment 7 - Operating Protocols between MISO Reliability Coordinator and the Transmission Operators on the following pages	9.0

Section 2.0: Gridforce Qualifications and Experience

2.1 Gridforce Core Capabilities and Services

NAES Corporation (NAES) is a multi-national services company providing independent, third-party operations and maintenance (O&M), engineering and technical, compliance, maintenance and construction, and business advisory services dedicated to making power generation, oil, gas, petrochemical, and industrial facilities run more safely, reliably, and cost-effectively. Headquartered in Issaquah, Washington, NAES was founded in 1980 and today exceeds 4,500 employees in more than 150 offices and plant sites in the U.S. and abroad. NAES is a wholly-owned subsidiary of ITOCHU Corporation, a Fortune Global 250 company.

Since 1987, NAES has specialized in providing O&M services in support of power generation facilities. NAES focuses on the fundamentals—safety, reliability, compliance, and cost—as it seeks to operate facilities as they were designed and intended to be operated, with a continuous emphasis on maximizing the capabilities of the facilities under our care. The implementation of a time-tested approach in conjunction with a corporate culture of continuous improvement yields exceptional results.

NAES acquired Gridforce Energy Management, LLC in June of 2017. Based in Houston, Gridforce provides energy control and integration management services to transmission, merchant generation, micro-grids, load-serving entities and demand response clients throughout North America. With nearly twenty years of control center operations experience, Gridforce focuses on safety, reliability compliance and cost-effectiveness for each client.

"Integrating Gridforce into our Power Services Group adds a layer of expertise in balancing and monitoring of power flows that we have not previously offered. It also augments our NERC reliability, asset management, and energy accounting capabilities."

NAES President & Chief Operating Officer Tom Bartolomei
07/26/2017 Press Release Power Magazine

Gridforce Energy Management, LLC (Gridforce), a wholly-owned subsidiary of NAES, was originally established as Duke Energy Control Area Services, LLC (DECA) in 2000. Duke Energy North America (DENA) envisioned a fleet management strategy for several thousand megawatts of merchant generation implemented across North America through DECA. DECA built a 24 x 7 control center and employed ESCA to install an Energy Management System, which would allow the operation of multiple, disparate operating areas within one central control center system and meet utility standards for data acquisition and control.

Gridforce brings a proven track record of integrating resources into the systems used in the control center, integrating with Reliability Coordinators, Transmission Operators and adjacent Balancing Authorities and succeeding in audits with no penalties ever issued.

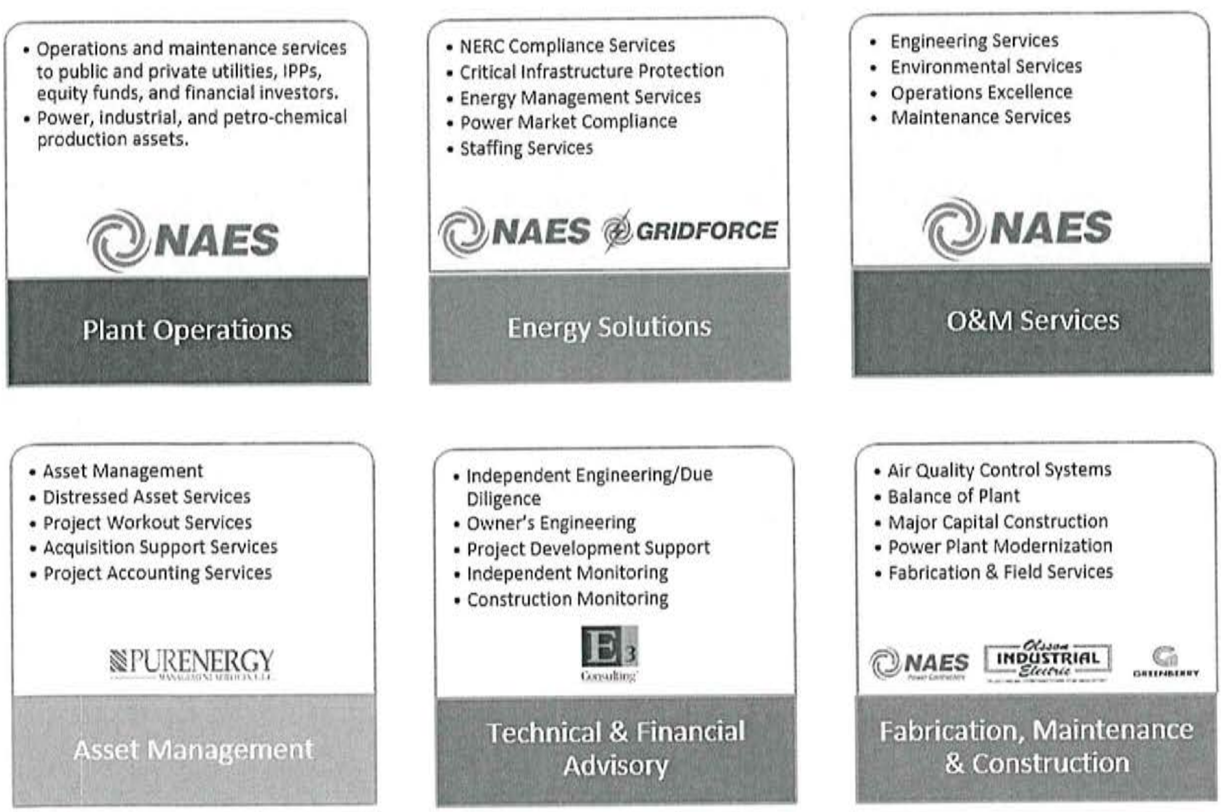
- +30 certification reviews by NERC and Regions
- NERC Readiness Audit 2007
- SERC Audits 2007, 2010, 2013
- WECC Audits 2007, 2010, 2016
- Reliability First Audit 2016
- PJM Audits 2013, 2018

Gridforce is highly experienced in the requirements that are applicable to a Balancing Authority and Transmission Operator including: communication and response to operating instructions; data acquisition and scan rates required to support real-time calculations; identify meter errors; calculate losses; and, gathering after-the-fact hourly data, frequency data, status information for equipment, protection systems, data sharing, outage coordination, emergency procedures, planning processes and cyber security.

2.2 NAES Family of Companies and Comprehensive Services

Delivering performance and economic value requires a sophisticated and proven combination of experience, skill-sets, programs, technical expertise, capacity, resources, management, and responsiveness. Our goal goes beyond traditional operations. NAES has the proven commitment required to assess options and to identify opportunities for improvement and to maintain, and ultimately enhance value.

NAES, as a reliable partner in the power market for more than 30 years, believes delivering solutions to individual customer needs is the only way to add real value – understanding that value to a long-term service utility is different than value to a short-term financial investor. NAES customized programs, and predictive and preventive solutions provides cost-conscience and sustainable benefits to ensure performance, competitiveness, profitability and alignment with client strategic goals. NAES power services are built from the ground up to provide life-cycle services. NAES growing business offers an expanding range of services, as illustrated below.



2.3 Gridforce Experience

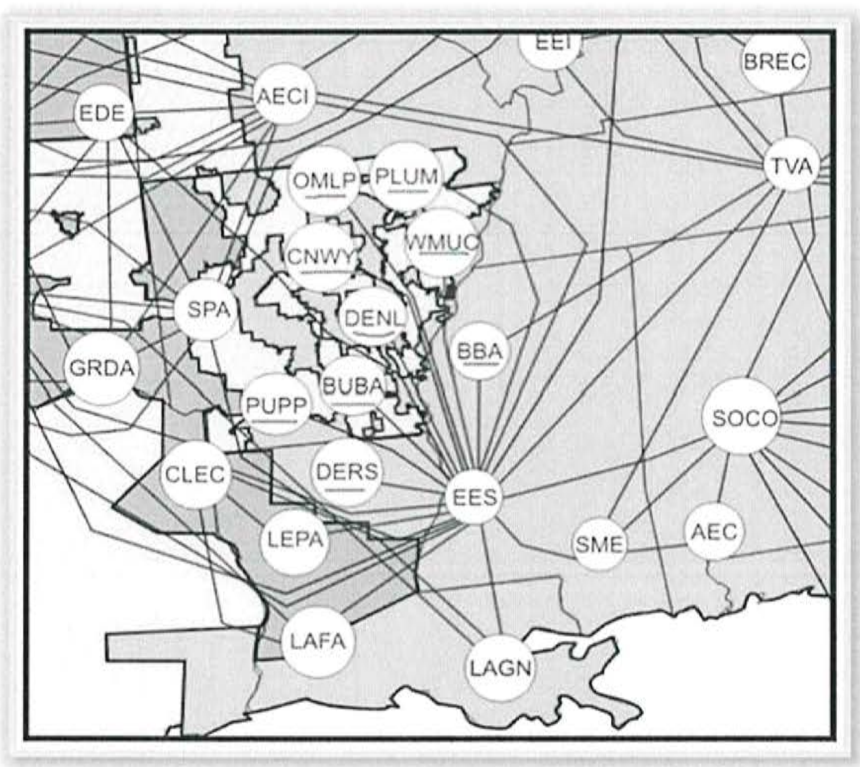
Gridforce has been operating and providing reliability services since 2001. Gridforce is a specialized team that is focused entirely on the reliable operation of specific assets. This focus on reliable operation of distributed assets has driven Gridforce to implement cost-effective best practices and assume a leadership role in asset integration throughout the Western and Eastern Interconnections.

GRIDFORCE BALANCING AUTHORITY (BA) EXPERIENCE			
Client	**System or Plant Name**	**Technology**	**Location**
	SERC		
City of North Littlerock	City of North Littlerock	Load	Arkansas
City of Ruston	City of Ruston	Load	Louisiana
City of Conway	City of Conway	Load	Arkansas
City of Benton	City of Benton	Load	Arkansas
City of Osceola	City of Benton	Load	Arkansas
City of West Memphis	City of West Memphis	Load	Arkansas
Goldman Sachs	Batesville Energy	Combined Cycle	Arkansas
Union Power Partners	Union	Combined Cycle	Arkansas
Dynegy	Plum Point	Coal	Arkansas
Duke Energy North America	Murray 230	Combined Cycle	Georgia
Duke Energy North America	Murray 500	Combined Cycle	Georgia
Duke Energy North America	Audrain	Simple Cycle	Missouri
Duke Energy North America	Marshall	Simple Cycle	Kentucky
Duke Energy North America	Hinds	Combined Cycle	Mississippi
Duke Energy North America	Southaven	Simple Cycle	Mississippi
Duke Energy North America	Enterprise	Simple Cycle	Mississippi
Duke Energy North America	Sandersville	Simple Cycle	Georgia
Duke Energy North America	New Albany	Simple Cycle	Mississippi
	ECAR		
Duke Energy North America	Vermillion Generation	Simple Cycle	Illinois
Duke Energy North America	Washington	Combined Cycle	Ohio
Duke Energy North America	Hanging Rock	Combined Cycle	Ohio
	MAIN		
Duke Energy North America	Lee County Generation	Simple Cycle	Illinois
	SPP		
Duke Energy North America	McClain	Combined Cycle	Oklahoma
	TRE		
Brazos Electric	Brazos Electric	Load	Texas
	RFC		
American Municipal Power, Inc.	AMP Fremont Energy Center	Combined Cycle	Ohio
	WECC		
Avangrid Renewables Holdings, Inc.	Avangrid Renewables Holding, Inc.		Maine
Avangrid Renewables Holdings, Inc.	Big Horn 1	Wind Power	Washington
Avangrid Renewables Holdings, Inc.	Big Horn 2	Wind Power	Washington
Avangrid Renewables Holdings, Inc.	Hay Canyon Windfarm	Wind Power	Oregon
Avangrid Renewables Holdings, Inc.	Juniper Canyon Windfarm	Wind Power	Washington
Avangrid Renewables Holdings, Inc.	Klamath Falls Cogen	CHP	Oregon
Avangrid Renewables Holdings, Inc.	Leaning Juniper II Windfarm	Wind Power	Washington
Avangrid Renewables Holdings, Inc.	Pebble Springs Wind LLC	Wind Power	Oregon
Broadview Energy Limited	Broadview Energy JN	Wind Power	New Mexico
Broadview Energy Limited	Broadview Energy KW	Wind Power	New Mexico
Consolidated Asset Management Services	Mesquite Generation Complex (PB2)	Combined Cycle	Arizona
Gila River Power, LLC	Gila River Station	Combined Cycle	Arizona
IdaWest - TransCanada	Hermiston Power Plant	Combined Cycle	Oregon
Naturener USA	Glacier Wind	Wind	Montana
Naturener USA	Windwatch	Wind	Montana
New Harquahala Generating Company, LLC	Harquahala Generating Facility	Combined Cycle	Arizona
Perennial Power Holdings Inc.	Hermiston Generating	Combined Cycle	Oregon
PUD Chelan County	Rocky Reach and Rock Island Dams	Hydroelectric	Oregon
Star West Generation, LLC	Griffith Energy Project	Combined Cycle	Arizona
Sundevel Power Holdings, LLC	Sundevil Power Holdings, LLC	Transmission	Arizona
TransAlta Centralia Generation LLC	Centralia Power Station	Combined Cycle	Washington
Valley Road, LLC	Arlington Valley Energy Facility	Combined Cycle	Arizona

Balancing Authority Experience

Gridforce currently operates as a registered Balancing Authority under the acronym GRID in the Western Interconnection with a footprint of approximately 4000 MW. In addition, Gridforce provide Balancing Authority services to other registered Balancing Authorities pursuant to delegation agreements in the west.

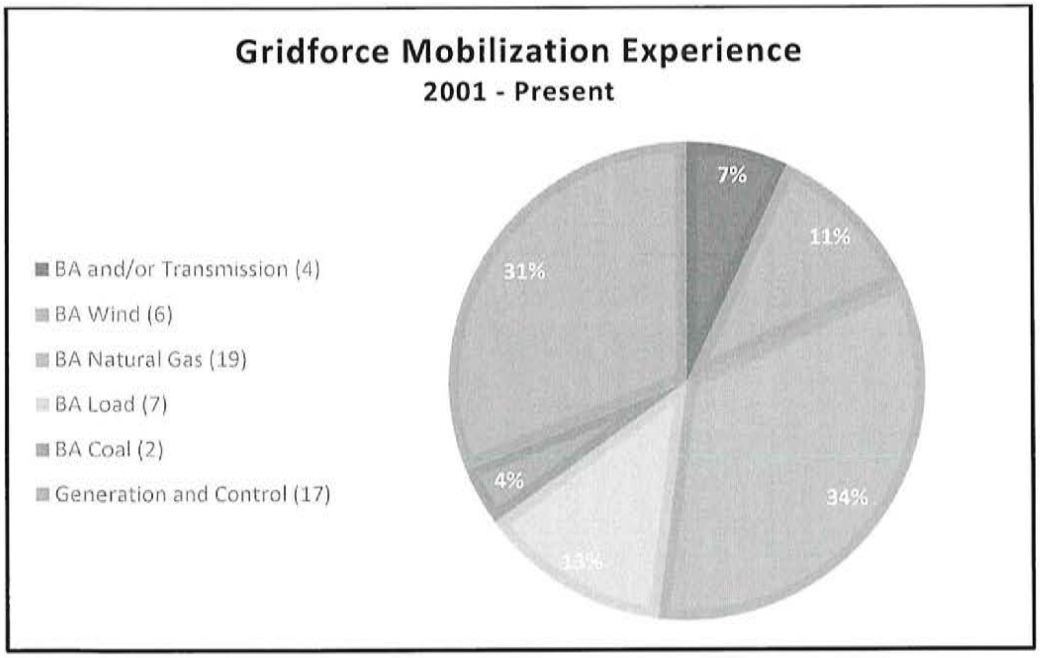
Gridforce has provided Balancing Authority services for over forty Balancing Authorities, including Balancing Authorities in the SERC region. Gridforce has provide services to several cities and municipalities and generation stations in SERC from 2002 – 2013. During this time Gridforce provided Balancing Authority services to transmission dependent entities inside the SERC footprint (North Little Rock, Benton, Ruston, Conway, West Memphis, Osceola, Brazos Electric, Plum Point, Batesville, Union Power Partners) and maintained a productive working relationship with the neighboring Balancing Authority and Transmission Operator



Note: Former Gridforce Balancing Authority clients in SERC underlined in red.

2.3.2 Mobilization Experience

Gridforce has a successful record of conducting certification and footprint expansion activities under the NERC rules of procedure, with services that include field engineering and support for telemetry communications equipment, ICCP communications, process development and implementation, training and staffing of our NERC Certified System Operators and Bulk Electric System operation applications engineering and maintenance. These projects have included both merchant generation, municipalities, and interconnected transmission facilities, operated by union and non-union personnel in U.S. locations.



2.3.3 Gridforce Contract Structure

Gridforce combines its years of experience in providing reliability services with a contract structure with fixed cost, clearly delineated roles and responsibilities, and continuation services should a modification to the services be needed or economically beneficial to the HMP&L. Gridforce understands the requirements associated with the NERC Transmission Operator function, including the coordinated functional registration with MISO specific requirements. Gridforce and HMP&L will use a detailed exhibit to reflect the roles and responsibilities that need to be addressed as well as document the areas where MISO is the responsible entity to ensure that are responsibilities are addressed.

2.3.4 Gridforce Transmission Operator Experience

Gridforce has been providing Transmission Operator services since 2009, leveraging the years of experience in the Balancing Authority services gathering real-time data, enhancing training around protections systems, switching procedures, outage coordination, restoration and voltage scheduling. The Balancing Authority and Transmission Operator functions align very closely and in many cases despite a separate requirement being placed on a Balancing Authority or Transmission Operator the obligations are mirror images or only slightly modified requirements.

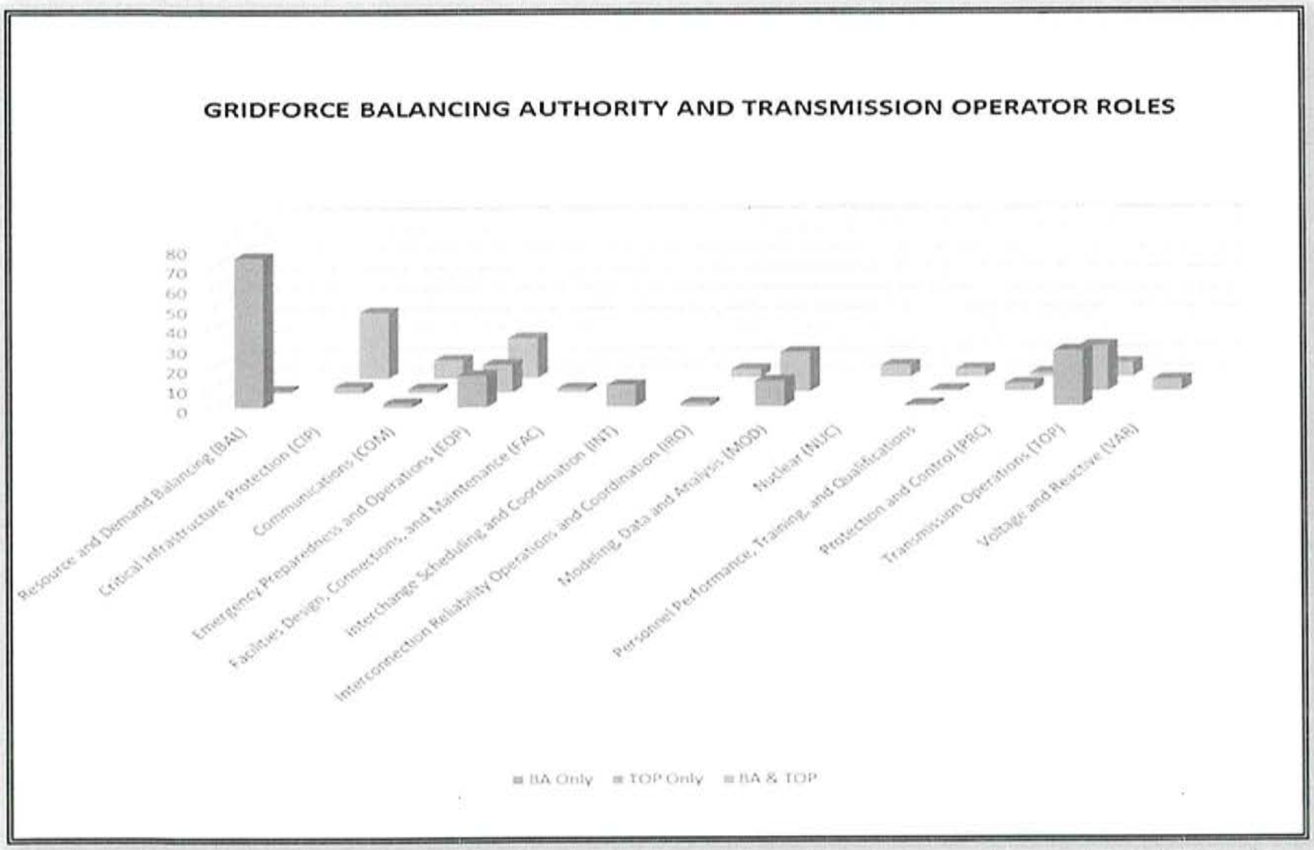
GRIDFORCE TRANSMISSION OPERATOR (TOP) EXPERIENCE					
NERC Region	**RTO**	**Client**	**System or Plant Name**	**Technology**	**Location**
RFC	PJM	American Municipal Power, Inc.	AMP Fremont Energy Center	Combined Cycle	Ohio
WECC	West Connect	New Harquahala Generating Company, LLC	Harquahala Generating Facility	Combined Cycle	Arizona
RFC	PJM	Cogentrix Energy Power Management LLC	Rock Springs Generation Facility	Simple Cycle	Maryland

Transmission Operator Services and Balancing Authority Services overlap in many operational areas, as bulleted below.

- Highly qualified System Operators

- Systems that provide real-time monitoring and control
- Redundant control center communications (voice and data)
- Cyber and Physical security
- Emergency procedures
- Operations planning and assessments
- Outage Coordination
- Data exchange with Reliability Coordinators and neighboring entities.

The graph below highlights Gridforce Balancing Authority and Transmission Operator Roles.



2.4 Gridforce Management Team

- **CJ Ingersoll, President**

CJ Ingersoll graduated from the University of Houston Law Center in 1999 and is a Licensed Attorney in the State of Texas. CJ started her legal career as a solo practitioner prior to shifting to a career in the energy sector as a System Operator at Duke Energy North America in 2001. She transitioned from real-time system operations to compliance program development and management on behalf of clients while engaging in strategic business development activities. From there, CJ moved to a new role serving as Associate General Counsel where she gained experience in corporate governance and regulatory requirements. Since 2015, she has been the leader of the Gridforce team expanding its existing core transmission and balancing authority services, and expanding generation control, microgrid, and cyber security service lines.

- **Denise Ayers, Vice President – Project Manager for the HMP&L Project Services**

Denise holds a BS in Business Management and an MBA in Public Administration with over 30 years' experience in power plant operations, utility system operations and management. Denise is SERC certified in ADDIE/SAT training principles and has also achieved NERC Reliability Coordinator operator certification, ERCOT operator certification, WECC operator certification, and PJM Generation and Transmission certifications. Denise manages day-to-day activity within Gridforce and is responsible for business operations and coordination of technical staff to support operations.

Denise will be the Gridforce Project Manager on this assignment.

- **David Jones, Operations Director**

David has a BS in Business Administration with over 30 years of experience in the electric utility industry including power plant operation, power systems control and dispatch, and management. David holds NERC Reliability Coordinator Certification, ERCOT Operator Certification, WECC Operator Certification, PJM Generation and Transmission certifications. David manages the Gridforce control center and the team of System Operators servicing clients 24 hours a day.

- **Antonio Franco, Director of Compliance Reliability**

Antonio has a BS in Industrial Engineering and is a certified Lean Six Sigma Black Belt. He has 9 years of experience in the electric industry as a Lean Six Sigma Black Belt, NERC Compliance Process Engineer and Internal Auditor. He has facilitated and managed several Lean Six Sigma projects in Power Operations and Commercial Operations (Trade Floor) including; Management of Power Plant Change, Natural Gas Pipeline Routing/Nomination and actualization processes, CAISO MRTU Trading and Settlements, Turbine Maintenance scheduling and back office processes. Antonio has experience developing standard operating procedures and swim lane diagrams to comply with NERC Reliability Standards for BA, GO, GOP, TO and TOP functions. Antonio is also a member of the NERC Resource Subcommittee.

- **Michelle Pellon, Security Engineer**

Michelle is the Network Security Engineer for Gridforce. Michelle holds a BS in Computer Science from Trinity University with 10 years' experience working in Information Security and Risk Management. Michelle has worked on cybersecurity challenges in both the public and private sector in industries as diverse as education, healthcare, payment processing and aviation. Michelle's role is to interpret cybersecurity-related regulatory, industry compliance and audit requirements and implement technical products, processes and procedures to meet those requirements. Michelle is an active member of the FBI's InfraGard public/private partnership and regularly contributes to the Critical Infrastructure Protection SIG.

- **Ben Bernier, Training and Performance Manager**

Ben has over 15 years of experience in power plant and bulk electric power system operations. Ben holds a BS in Marine Engineering from the Maine Maritime Academy; NERC Reliability Coordinator, PJM Generation and PJM Transmission Certifications; and a 3rd Class Stationary Steam Engineer License in the State of Maine. Ben maintains the Gridforce Learning Management System and designs and delivers training to Gridforce staff, vendors, and customers that meet performance goals in compliance and reliable system operations.

Section 3.0: Project Approach

3.1 Local Balancing Authority and Transmission Operator Services

A Local Balancing Authority is an operational entity or Joint Registration Organization, as defined in the NERC Rules of Procedure, which is:

(i) responsible for compliance to NERC for the subset of NERC Balancing Authority Reliability Standards;

(ii) a Party to the Amended Balancing Authority Agreement (Amended Agreement); and,

(iii) shown in Appendix A of the Amended Agreement.

3.2 Implementation Services

In accordance with NERC Rules of Procedure in Appendix 5A, Gridforce will, in coordination with MISO, initiate the certification procedure with SERC and move forward with the process of implementing the infrastructure to support the LBA and TOP services. Gridforce will:

- Review diagrams (protection systems, communications, and equipment) and physical characteristics of the HMP&L facilities.
- Perform a site visit to identify metering (Current Transformers and Potential Transformers), evaluate power supplies, and verify field equipment locations, and data exchange paths to Gridforce.
- Order equipment that will be installed such as: Rack, Router, Switch, RTU, EMS Front-end Server, Remote Terminal Unit, Frequency Measurement Device, Power Distribution Units, and Uninterruptible Power Supplies.
- Develop a Data Points List applicable to the project to support Gridforce Monitoring and Real-time Assessments, IRO-010 and TOP-003 the data requests.
- Model the transmission facilities in the Gridforce applications; the Energy Management System, Energy Accounting, the Historian, and ICCP Communications.
- Order and turn up of redundant data circuits.
- Perform point-to-point testing of data between HMP&L facilities, MISO, the neighboring entity and Gridforce.
- Modify and/or develop procedures and processes for HMP&L facilities, including emergency procedures, field personnel dispatch, and restoration.

Gridforce believes there is the potential to meet the services start date of the client if permitted to initiate services using ICCP and parties with direct connections agree to share information with Gridforce, though the full project implementation cannot be completed within this window primarily due to timelines required to implement communications directly with HMP&L. Gridforce provides the below targeted accelerated schedule showing the potential for meeting the start date target but adds this is a very aggressive schedule that Gridforce will use best efforts to meet.

Gridforce Project Tasks

ID	Task Name	Duration	Start	Finish
1	**Contract Execution**	13 days	Wed 12/12/1	Fri 12/28/18
2	**Initiate and Implement Project with MISO**			
3	Agreement Review and Execution	22 days	Wed 1/2/19	Thu 1/31/19
4	MISO WAN Order and Turn Up	86 days	Wed 1/2/19	Wed 5/1/19
5	ICCP Data Exchange (points lists creation and modeling)	22 days	Wed 1/2/19	Thu 1/31/19
6	EMS Modeling Coordination	22 days	Wed 1/2/19	Thu 1/31/19
7	MISO Tools Coordination	22 days	Wed 1/2/19	Thu 1/31/19
8	**Site Activity**			
9	Site Visit Coordination & Execution	10 days	Wed 1/2/19	Tue 1/15/19
10	Communications Design, Field Equipment and	24 days	Tue 1/15/19	Fri 2/15/19
11	Circuit Orders	8 days	Thu 1/31/19	Sun 2/10/19
12	Field Equipment Orders	8 days	Thu 1/31/19	Sun 2/10/19
13	Field Equipment Configuration	11 days	Mon 4/1/19	Mon 4/15/19
14	Circuit Turn Up and Testing	9 days	Sat 4/20/19	Wed 5/1/19
15	Field Equipment Installation and Testing	9 days	Sat 4/20/19	Wed 5/1/19
16	**Applications Development**			
17	EMS Modeling	22 days	Wed 1/2/19	Thu 1/31/19
18	SMP Modeling	11 days	Mon 4/1/19	Mon 4/15/19
19	Energy Accounting	22 days	Wed 1/2/19	Thu 1/31/19
20	Historian	22 days	Wed 1/2/19	Thu 1/31/19
21	OAG	22 days	Wed 1/2/19	Thu 1/31/19
22	Versify	64 days	Wed 1/2/19	Mon 4/1/19
23	**Compliance and Operations**			
24	Procedure Development	22 days	Wed 1/2/19	Thu 1/31/19
25	Training	22 days	Wed 1/2/19	Thu 1/31/19

3.3 Real-Time Operations Monitoring and/or Control

3.3.1 Gridforce Control Centers

Gridforce will operate the HMP&L facilities from its Primary Control Center (PCC) in downtown Houston, Texas and has stringent security controls including on-site security, cameras and physical access control managed by the building and Gridforce. The PCC is connected to building power, a UPS and an on-site generator in addition to having separate environmental controls.

The Back-Up Control Center (BUCC) is located about 40 minutes west of downtown Houston, Texas and has stringent physical security controls including on-site security, cameras and physical access controls managed by the building and Gridforce. The BUCC is connected to building power, a UPS and an on-site generator in addition to having separate environmental controls. The BUCC has four (4) System Operator workstations with each station configured to perform all job tasks.

Gridforce's primary and backup control centers comply with all applicable NERC standard including but not limited to physical and cyber security standards.

In addition, Gridforce maintains loss of control center procedures to ensure operations remain continuous and transparent to its customers not only from the BUCC is necessary but for operation from tertiary secure remote capabilities that allow for reliable operations to be maintained during high-impact, low-probability events, such as hurricanes. Those plans include weekly testing and training of operations staff and backup control center operations.

3.3.2 Gridforce Certified System Operators

Gridforce staffs the Houston-based control center at all times with NERC Certified System Operators that are certified at the Reliability Coordinator level. In addition, each qualified Gridforce System Operator maintains transmission certifications to ensure they have the appropriate knowledge and skill to operate reliably. In fact, Gridforce identifies training and system operator knowledge as a key business strategy because these individuals are the front lines for reliable system operation. Gridforce System Operators are continuously undergoing training on specific assets and procedures, emergency operations, restoration procedures, and outage coordination. We focus on critical thinking skills to make certain System Operators are capable of responding to real-time conditions that may not be covered by established procedures.

3.3.3 Energy Management System

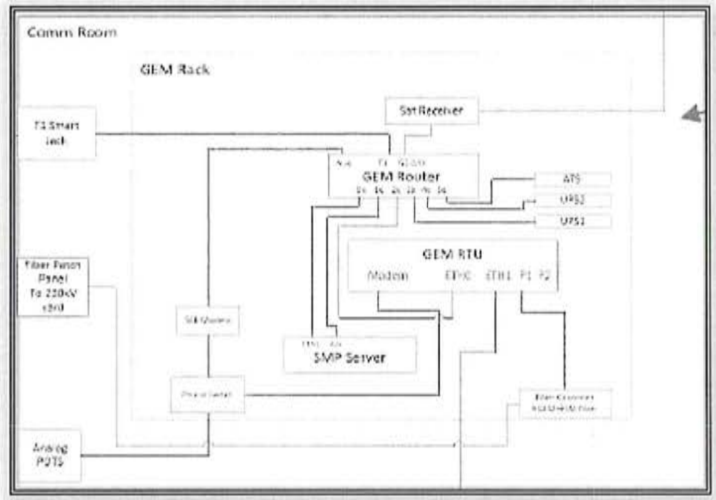
The primary system used by Gridforce System Operators is the GE (formerly Alstom) Energy Management System (EMS), a system that is widely used by Balancing Authorities and Transmission Operators to monitor real-time conditions and initiate action for maintaining reliability.

Reliable operation of the EMS is supported by data inputs from critical field devices, so to provide a complete picture of real-time monitoring and control functionality leveraged by Gridforce HMP&L would permit installation of the appropriate field equipment described below.

3.3.4 Field Equipment

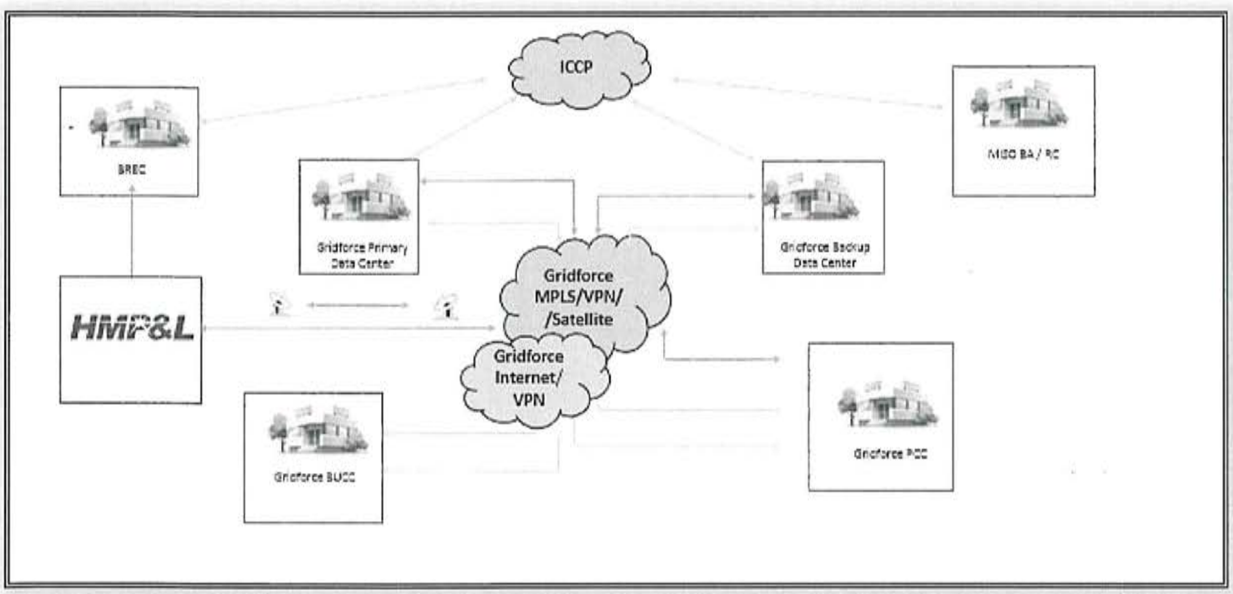
A secure rack located in a secure location with appropriate physical access controls limited to authorized individuals by HMP&L will host field equipment, low impact Bulk Electric System cyber assets, used for real-time monitoring and control by Gridforce System Operators. The rack will have appropriate devices to support reliable operation from the Gridforce Control Center, such as:

- Redundant power supplies/Power Distribution Units
- An Automatic Transfer Switch and Uninterruptible Power Supply
- A redundant Router/Firewall/Switch
- A Remote Terminal Unit (RTU)
- A SCADA Management Platform Front-end Server
- A Frequency Measurement Device
- A Satellite Receiver



3.3.5 Communications

Highly robust and redundant communications will be implemented to support continuous real-time monitoring and control capability. Gridforce requires redundant communication paths through different providers, subject to periodic failover testing, to its redundant data centers from the HMP&L facilities. In addition, Gridforce has established redundant communications between the primary and backup control centers and the redundant data centers. This redundancy is further enhanced using ICCP communications with the reliability coordinator and neighboring entity to provide tertiary communications for the HMP&L facilities.

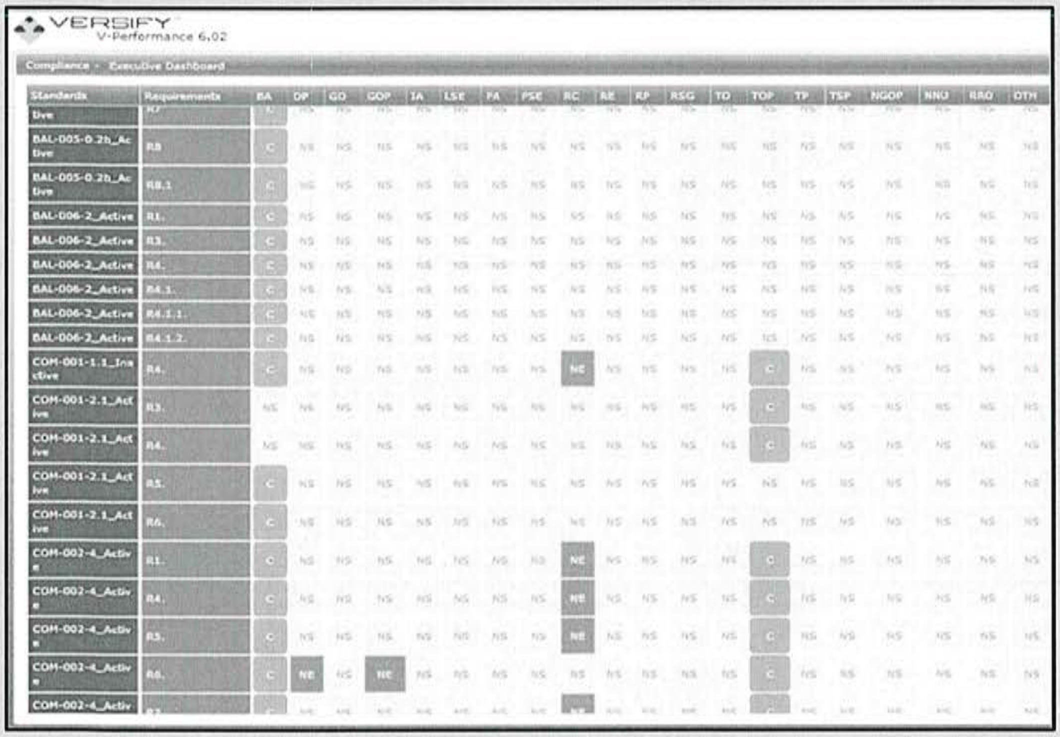


3.3.6 Data Centers

Each data center hosting the systems and applications to be used to operate the HMP&L facilities has stringent physical security controls at the perimeter and ingress points including on-site security, cameras, and multiple layers of physical access controls. Within each data center is a dedicated cage with physical access that is controlled and maintained by Gridforce (two-factor authentication) where Gridforce servers are located. Redundant EMS and ICCP servers, isolated on their own network, are hosted at each data center.

3.3.7 Internal Controls

Gridforce has established appropriate internal controls to monitor the services and gather evidence of compliance to stay audit ready at all times. Gridforce uses a combination of time-based reminders and workflows through a program jointly developed with software solution provider Versify called NETCompliance, which includes a NERC standards data base that supports evidence collection at the individual requirement level.



3.4 Outage Coordination

3.4.1 Planned Outage Coordination

Gridforce will serve as the point of contact for outage coordination with MISO and the neighboring Transmission Operator, collecting Planned Outage information for the transmission facilities including transmission lines, transformers, and breakers and submitting outages to MISO for approval in accordance with MISO's outage coordination procedures.

3.4.2 Force Outage Coordination

Gridforce will serve as the point of contact for forced outage coordination with MISO, identifying forced outage conditions, performing verifications with field personnel, and providing phone notifications to MISO and following up with outage reports as applicable.

3.4.3 Switching Coordination

Gridforce places safety of field personnel as the highest priority when crafting any switching orders. There are two main component the first being that Gridforce will maintain and utilize its existing Lock-Out / Tag-Out procedures to establish high level processes and procedures about how to safely isolate transmission facilities for the protection of personnel performing work. Secondly, Gridforce will work closely with HMP&L and the neighboring Transmission Operator, as applicable, to develop switching orders that are actually issued to field personnel.

GEM Lock-Out / Tag-Out Procedure

A switching order involves close coordination with personnel that actually have their hands on the equipment and interconnected entities. Upon receipt of a planned outage request Gridforce will draft a switching order to both isolate and restore the facilities. If the switching is a coordinated activity with the neighboring Transmission Operator, the draft switching order will be provided to HMP&L field personnel and the neighboring TOP for review and validation. Upon agreement of the affected parties the switching order is finalized as a Master Copy. All verbal communications relating to switching activity will use three-part communications in accordance with Gridforce communication protocols. Prior to executing the switching order Gridforce will notify the MISO Reliability Coordinator and the neighboring Transmission Operator that the scheduled switching activity will be initiated.

3.5 Roles and Responsibilities

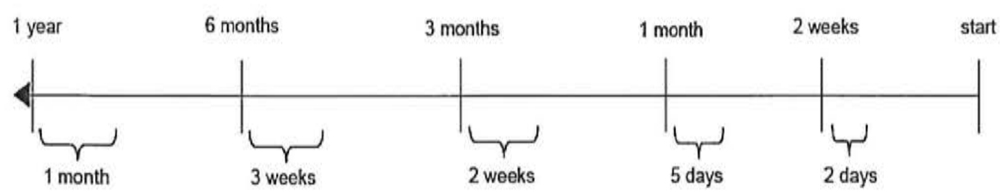
Below are excerpts from the Gridforce Outage Coordination procedure included as an illustration of the outage coordination process that is used by Gridforce:

- Gridforce and HMP&L will develop a list of the facilities serviced by Gridforce and classify the facilities using MISO Criteria for Classification of Facilities: Class I, Class II, Class III, or Class IV. Gridforce will coordinate the list with MISO and notify HMP&L of any modifications or changes made by MISO.
- HMP&L will notify Gridforce immediately by phone **713.332.2920** of any outage condition that cannot

be timely coordinated through normal procedures, including Urgent/Emergency outage conditions.

- HMP&L is responsible for providing Gridforce additional information about Urgent and Emergency outage conditions via the Gridforce Outage System or via email at gccdispatch@grid4ce.net as soon as possible with proposed schedules as coordinated with field personnel.
- HMP&L is responsible for developing schedules for planned outages and submitting the schedules (including any updates or modifications) to the Gridforce Outage System. Owner will make efforts to plan and schedule outages at times when outages are less likely to impact system reliability.
- Gridforce will notify MISO and neighboring Transmission Operators immediately by phone of any outage condition that cannot be timely coordinated through normal or opportunity outage coordination procedures, including Urgent and Emergency outage conditions.
- Gridforce will submit outage information into the MISO coordinated outage systems as soon as possible after receipt from HMP&L and monitor the status, submit updates and changes and respond to potential status changes as appropriate, including coordination with MISO and HMP&L.
- Gridforce will coordinate with the MISO RC using the Outage Notification Process verifying switching activity. (See SO-P-NOP-00411)
- MISO approves outages if MISO's outage analysis indicates next-contingency system conditions are acceptable (no overloads beyond emergency ratings, no excessive or inadequate voltage condition is identified, no loss of system stability condition identified.)
- MISO may permit an outage to proceed that may result in unacceptable conditions provided Gridforce and MISO have developed an appropriate Operating Guide per established timelines.

Exhibit 0-1: Timeline for MISO's Response to Outage Request



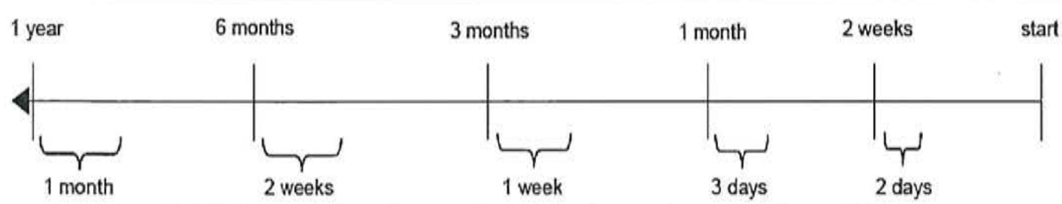


Exhibit 5-2: Timeline to Provide Operating Guide to MISO

1. *MISO has the authority to deny or reschedule planned Transmission Outages and return transmission facilities to service*
2. *MISO works with Gridforce to develop mitigation plans if appropriate for specific outages.*

Section 4.0: Indicative Pricing Summary

4.1 Gridforce Pricing Summary

A summary of the implementation cost estimate and the proposed services fees is provided in the table below.

Pricing Summary			
Phase	Description	Note	Price
Implementation	Transition to Gridforce 24x7 Control Center:		
	One (1) Site Surveys		$ 20,000
	One (2) Routers		$ 20,000
	One (1) Remote Terminal Units		$ 20,000
	Two (2) Power Distribution Units		$ 1,800
	Two Uninterruptible Power Supply		$ 1,800
	One Secure Encasement of Power Equipment (Rack)		$ 1,800
	Equipment Installation		$ 20,000
	Systems Modeling		$ 30,000
	Energy Accounting		$ 10,000
	ICCP Data Exchange		$ 20,000
	Testing		$ 20,000
	Procedures Modification		$ 20,000
	Training		$ 10,000
	Project Management		$ 20,000
	Estimated Gridforce Implementation Costs		**$215,400**
Services	Gridforce Services Fee		$600,000/year
	Gridforce Site Equipment Maintenance Fee		$10,000/year
Term	Three Year Initial Term and two automatic annual renewals		5 years

4.2 Assumptions

Gridforce bases its submittal on the following assumptions:

- One site survey completed in one day by two (2) field engineers.
- Equipment Installation will be completed in one day by two (2) field engineers.
- Implementation costs and ongoing services fees do not include installation fees, expenses, or cost for installing data circuits or the monthly charges and fees for data circuits.
- Implementation costs and ongoing services fees do not include communication between the HMP&L substations to support protection systems or to aggregate data to the agreed upon location where Gridforce field communication equipment will hosted.
- HMP&L will provide an appropriate structure (power supplies, batteries, physical security, and environmental controls) for communications equipment used by Gridforce and installed at the mutually agreed upon location.
- HMP&L will provide existing points lists within 1 week of the project start date to enable modeling required to support an accelerated schedule.

Section 5.0: Proposed Services Agreement

Gridforce has included a draft Services Agreement on the following pages.

LOCAL BALANCING AUTHORITY

AND

TRANSMISSION OPERATOR SERVICES AGREEMENT

by and between

GRIDFORCE ENERGY MANAGEMENT, LLC

And

CITY OF HENDERSON

THIS LOCAL BALANCING AUTHORITY AND TRANSMISSION OPERATOR SERVICES AGREEMENT (this "Agreement") is made and entered into as of this __ day of ___________, 20__ (the "Effective Date") by and between GRIDFORCE ENERGY MANAGEMENT, LLC, a Delaware limited liability company ("Gridforce" or "GEM"), and CITY OF HENDERSON ("Customer"). Gridforce and Customer are sometimes hereinafter referred to individually as a "Party" and collectively as the "Parties."

WITNESSETH

WHEREAS, Gridforce is registered with NERC as a Balancing Authority and is engaged in the business of providing Balancing Authority and Transmission Operator Services;

WHEREAS, Customer owns four (4) 69 kV Tie Lines, two (2) 161 kV Tie Lines, 34.86 miles of 69 kV distribution line, 22 miles of 161 kV transmission line, one (1) 161 kV substation and seven (7) 69 kV substations in Kentucky (the "Facility");

WHEREAS, Gridforce has agreed to provide Local Balancing Authority Services and Transmission Operator Services for the Customer's Facility consistent with the MISO Rate Schedule 01, Transmission Owners Agreement, MISO Rate Schedule 03 the Amended Balancing Authority Agreement (Amended BAA) in accordance with the terms and subject to the conditions set forth in this Agreement (the "Services", as defined below);

NOW, THEREFORE, in consideration of the mutual promises and agreements set forth herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

ARTICLE 1.
DEFINITIONS

Section 1.1. Definitions. As used in this Agreement, the terms that are defined in the NERC Glossary of Terms shall have the definitions provided in such glossary, and the following defined terms shall have the respective meanings set forth below:

"Abnormal Operating Condition" means any condition on the Customer Facility, Interconnection Facilities, Interconnected Transmission System or the transmission system of other utilities which is outside normal operating parameters such that facilities are operating outside their normal ratings or reasonable operating limits have been exceeded but which has not resulted in an Emergency. An Abnormal Operating Condition may include high or low deviations in voltage or power system stabilizers.

"Adjacent Balancing Authority" has the NERC meaning in the NERC Glossary of Terms.

"Affiliate" means, with respect to any Person, any other Person (other than an individual) that, directly or indirectly, Controls, or is Controlled by, or is under common Control with, such Person.

"Balancing Authority" has the NERC meaning in the NERC Glossary of Terms.

"Balancing Authority Area" has the NERC meaning in the NERC Glossary of Terms.

"Bulk Electric System Facilities" means the 161 kV substation and 22 miles of 161 kV transmission line owned by Customer.

"Facility Services Committee" has the meaning set forth in Section 4.11 of this Agreement.

"Business Day" means a day on which Federal Reserve member banks in New York City are open for business; and a Business Day shall open at 0800 and close at 1700 Eastern Prevailing Time (EPT).

"Certification" shall have the meaning described in the NERC Rules of Procedure.

"Change of Law" means the occurrence after the Effective Date of any of the following events: (a) any adoption, amendment or repeal of any Governmental Rule, whether published or unpublished, or any change therein or change in the interpretation or application thereof by any court, administrative agency, other Governmental Authority from that in effect on the Effective Date; or (b) the imposition by any Governmental Authority of any material condition, or the cessation of any such imposition, including but not limited to Remedial Action Schemes, NERC Alerts, in connection with the Services contemplated by this Agreement.

"Continuation Assistance" has the meaning set forth in Section 2.6 of this Agreement.

"Contract Term" has the meaning set forth in Section 2.1 of this Agreement.

"Contract Year" has the meaning set forth in Section 2.5 of this Agreement.

"Control" means the direct or indirect ownership of over fifty percent (50%) of the capital stock (or other ownership interest, if not a corporation) of any Person or the possession, directly or indirectly, of the power to direct the management and policies of such Person by ownership of voting securities, by contract or otherwise. "Controlling" shall mean having Control of any Person, and "Controlled" shall mean being the subject of Control by another Person.

"Customer Equipment" means equipment owned or controlled by Customer or its Affiliate, including the Customer Facility and equipment installed at the Facility to implement this Agreement.

"Effective Date" means the date that Customer executes the Agreement for the Facility.

"Emergency" has the meaning set forth in the NERC Glossary of Terms.

"Facility" has the meaning set forth in the Recitals.

"Facility Operating Limits" means the manufacturer's design limitations, equipment warranties and permit limits of the Facility established by Customer.

"Facility Services Committee" has the meaning set forth in Section 4.11 of this Agreement.

"FERC" means the Federal Energy Regulatory Commission or any successor agency that has jurisdiction over NERC.

"Force Majeure" means fire, flood, earthquake, other extreme elements of nature or acts of God, war, terrorism, riots, rebellions, revolutions, civil disturbances, court or agency ordered injunctions, industry-wide or national labor disputes, criminal acts, and any other cause beyond a party's control to the extent these events: (a) prevent Customer from discharging its obligations under the MISO's tariff or the SDA or ancillary agreements thereto related to the performance of the Services or any other obligation under this Agreement or otherwise prevent all, or a portion of, the Facility from being completed by the required in-service date; (b) are outside the control of the party whose performance is to be affected by the event of Force Majeure; and (c) could not reasonably be foreseen or prevented by the Party whose performance is to be affected by the event of Force Majeure. Party claiming uncontrollable force must give prompt written notice and shall exercise due diligence to remove such inability with all reasonable dispatch.

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry operating in the Regional Entity during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability criteria, safety considerations and expediency, taking into account the design and operational characteristics of the Facility and the Bulk Electric System. Good Utility Practice is not intended to be limited to the optimum practice, methods, or act to the exclusion of all others, but rather includes all acceptable practices, method, or acts generally accepted in the region. Good Utility Practice shall include, but not be limited to, applicable law and regulatory requirements, and the criteria, rules and standards promulgated by the FERC, the NERC, the appropriate Regional Entity, the National Electric Safety Code, and National Electrical Code, as they may be amended from time to time, including the rules and guidelines and criteria of any successor organizations.

"Governmental Authority" means any national, state, provincial or local government, any political subdivision thereof, or any other governmental, regulatory, judicial, public or statutory instrumentality, authority, body, agency, department, bureau, or entity or any arbitrator with authority to bind a Party at law.

"Governmental Rule" means (i) any constitution, charter, act, statute, law, ordinance, code, rule, regulation or order of any Governmental Authority; (ii) any condition, specified standards or objective criteria contained in any applicable permit, approval, decision, determination or ruling of any Governmental Authority; or (iii) any other legislative, administrative or judicial action, final decree or judgment of any Governmental Authority; in each of the foregoing cases as in effect from time to time.

"Gridforce Alternate Control Center" means the GEM alternate operations center located, in Houston, Texas or such other alternate sites that are capable of meeting the Loss of Primary Control Center Reliability Standard.

"Gridforce Control Center" means the Gridforce primary operations center located in Houston, Texas or such other alternate sites that are capable of hosting the Services

"Gridforce Technology" has the meaning set forth in Section 3.3(a) of this Agreement.

"Gridforce Website" means the secure website, and secure web-based information system, accessible only by the Parties for purposes of viewing certain data regarding the Facility as provided in this Agreement.

"Implementation Services" has the meaning set forth in Section 3.1 of this Agreement.

"Local Balancing Authority Services" means the Services that Gridforce will perform as described in this Agreement and the obligations and responsibilities Gridforce has with respect to its compliance with delegated responsibilities per the Amended BAA and the Coordinated Functional Registration with MISO (CFR-001).

"Midcontinent Independent System Operator, Inc." (MISO) is the registered Balancing Authority and Reliability Coordinator for the Facility.

"Monthly Services Fee" means the Monthly Services Fee described in Exhibit C hereof.

"NERC" means the North American Electric Reliability Corporation or any successor Electric Reliability Organization that is certified by the FERC to establish and enforce NERC Reliability Standards for the Transmission System, subject to FERC review.

"NERC Glossary of Terms" means the Glossary of Terms Used in Reliability Standards adopted by the NERC Board of Trustees, as amended, modified or supplemented from time to time.

"NERC Reliability Standards" means a FERC approved requirement, whether now existing or hereafter amended, modified or supplemented from time to time, to provide for reliable operation of the bulk power system, including without limiting the foregoing, requirements for the operation of existing bulk power system facilities, including cyber security protection, and including the design of planned additions or modifications to such facilities to the extent necessary for reliable operation of the bulk power system; but shall not include any requirement to enlarge bulk power system facilities or to construct new transmission capacity or generation capacity.

"NERC Registered Entity" means the entity responsible to NERC for a function defined in the NERC Functional Model, such as a Balancing Authority and Transmission Operator.

"Optional Services" means additional services that are agreed to by the Parties as specified in an Optional Services Exhibit, which may be provided in addition to the Services, subject to the terms of this Agreement except as specified in the Optional Services.

"Person" means an individual, partnership, corporation, limited liability company, association, trust, unincorporated organization, Governmental Authority, or other form of entity.

"PUHCA 2005" means the Public Utility Holding Company Act of 2005 (enacted, effective February 8, 2006, by the Energy Policy Act of 2005), as it may be amended, and the regulations promulgated and rulings issued thereunder.

"Regional Entity" is an entity that has been delegated authority by NERC to perform certain actions and is responsible for monitoring and enforcing compliance with Reliability Standards.

"Section 2.5(a) Termination Notice" has the meaning set forth in Section 2.5(a) of this Agreement.

"Services" means the Local Balancing Authority Services, Transmission Operator Services, Implementation Services, and/or Optional Services (if any).

"Services Commencement Date" has the meaning set forth in Section 2.3(a) of this Agreement.

"Services Contract Year" has the meaning set forth in Section 2.3(b) of this Agreement.

"Services Term" has the meaning set forth in Section 2.3(a) of this Agreement.

"Termination Fee" shall mean an amount, as described in Exhibit C, payable by Customer to Gridforce in the event that Customer elects to exercise certain termination rights.

"Transmission Operator" has the meaning set forth in the NERC Glossary of Terms.

"Transmission Operator Services" means the processes, procedures, systems, communications, infrastructure and qualified personnel that are managed by Gridforce to comply with the responsibilities delegated per this Agreement to meet the reliable operation of the Facility in coordination with MISO and the neighboring Transmission Operator. These services include but are not limited to real-time monitoring, system operating limit exceedance mitigation, outage coordination, field personnel dispatch and communication, and event reporting.

ARTICLE 2.
TERM AND TERMINATION

Section 2.1. Contract Term. The term of this Agreement shall begin at 12:01 a.m. (Central Prevailing Time) on the Effective Date and, unless earlier terminated in accordance with the terms and conditions of this Article 2, shall continue through 11:59 p.m. (Central Prevailing Time) on the final day of the Services Term (the "Contract Term").

Section 2.2. Implementation Term. The term during which Gridforce shall perform the Implementation Services (the "Implementation Term") shall commence upon the Effective Date and continue until the earliest of the following to occur:

(a) the Services Commencement Date; or

(b) the expiration of twenty-four (24) months from the Effective Date, unless the Parties mutually agree to extend the Implementation Term.

Section 2.3. Services Term.

(a) The term during which Gridforce shall perform the Services (the "Services Term") shall commence on the date that Gridforce initiates the Services for the Customer as coordinated with MISO (the "Services Commencement Date").

(b) The Services Term shall continue for a period of three (3) years (each, a "Services Contract Year"), with the first Services Contract Year commencing on the Services Commencement Date and continuing until 11:59 p.m. (Central Prevailing Time) on the day before each anniversary of the Services Commencement Date. The Services Term shall thereafter automatically renew for one (1) year terms, unless written notice is delivered by one Party to the other at least ninety (90) days prior to expiration of the then current Services Contract Year indicating that the Services Term will terminate at the end of such Services Contract Year, subject to the continuation, transition and survival periods set forth in Sections 2.6. Any renewal or extension of the Services Term shall be on the same terms and conditions as set forth herein, unless modifications are required by a Governmental Authority or mutually agreed to by the Parties.

Section 2.4. [Intentionally Left Blank]

Section 2.5. Termination Rights. Neither Party shall have the right to terminate this Agreement except as follows:

(a) Customer Termination Option.

(i) Following the Effective Date, but prior to the Services Commencement Date, Customer may at its election and in its sole discretion for any reason or no reason (other than as otherwise provided in this Agreement) provided thirty (30) days prior written notice to Gridforce of termination of this Agreement (a "Section 2.5(a) Implementation Term Termination Notice"). A Section 2.5(a) Implementation Term Termination Notice must state: that Customer is electing to terminate this Agreement voluntarily under this Section 2.5(a) and the expected termination date for the Agreement. Customer shall pay Gridforce an Implementation Term Termination Fee following the sending of the Section 2.5(a) Service Term Termination Notice as set out in Exhibit C.

(ii) Following the Services Commencement Date, Customer may at its election and in its sole discretion for any reason or no reason (other than as otherwise provided in this Agreement) provide one hundred twenty days (120) days prior written notice to Gridforce of termination of this Agreement and, in its sole discretion, request Continuation Assistance (a "Section 2.5(a) Services Term Termination Notice"). A Section 2.5(a) Services Term Termination Notice must state: that Customer is electing to terminate this Agreement voluntarily under this Section 2.5(a), whether Customer is requesting Continuation Assistance from Gridforce, and the expected termination date for the Agreement. Customer shall pay Gridforce a Services Term Termination Fee following the sending of the Section 2.5(a) Service Term Termination Notice as set out in Exhibit C.

(b) Termination Pursuant to Default. Either Party may provide notice of termination of this Agreement in accordance with Article 7 of this Agreement.

(c) [Intentionally deleted.]

(d) Customer Termination Pursuant to Section 4.4(c) and 4.5. Customer may provide notice of termination of this Agreement in accordance with the terms of Section 4.4(c) and 4.5.

(e) Termination Pursuant to Section 15.5. Either Party may provide notice of termination of this Agreement in accordance with the terms of Section 15.5, and upon such termination no party shall have any further or remaining obligations or liabilities under this Agreement, except as expressly provided elsewhere in this Agreement, and Customer will not be required to pay a Termination Fee.

(f) Termination for Reliability Violations Caused by Gridforce. If Gridforce's failure to comply with its obligations under this Agreement (i) is the sole cause of a violation of the NERC Reliability Standards by the Customer, more than one (1) time in any Contract Year, or (ii) the aggregate total of all penalties, fines, fees and costs for violation of the NERC Reliability Standards caused by Gridforce that are levied against the Customer exceeds three (3) times the Monthly Services Fee in any Contract Year, then Customer shall have the right to terminate this Agreement immediately subject to Customer 's rights to Continuation Assistance. Upon such termination, Customer will not be required to pay a Termination Fee.

Section 2.6. Continuation of Services Following Expiration or Notice of Termination. In the event that Customer requests continued Services in writing at least ninety (90) days prior to the expiration or termination of the Contract Term, Gridforce shall continue to provide the Services, on the terms and subject to the conditions of this Agreement (including payment by Customer of the Monthly Services Fee and other amounts payable by Customer under this Agreement), for a maximum of one-hundred and eighty (180) days (the "Continuation Assistance") unless the Parties mutually agree to extend the Continuation Assistance. The quality and level of the Services shall not be degraded during the period Continuation Assistance is provided. In the event Continuation Services are provided following a Customer Event of Default, the Monthly Services Fee payable by Customer shall escalate in accordance with the payment schedule in Exhibit C hereof.

Section 2.7. Survival. This Agreement shall continue in effect after a notice of expiration or termination to the extent necessary (i) to allow Gridforce to provide the Continuation Assistance pursuant to Section 2.6, if applicable; or (ii) to allow Gridforce to provide the Services when Gridforce is providing Continuation Assistance pursuant to Section 15.5, if applicable. In addition, the following Sections survive any expiration or termination of this Agreement: Articles 1, 8, 9, 13, 14 and Sections 2.7, 3.4, 4.1(c), 4.7, 10.2, 15.2, and 15.12.

ARTICLE 3.
LOCAL BALANCING AUTHORITY AND TRANSMISSION OPERATOR SERVICES

Section 3.1. Implementation Services.

(a) Implementation Services. The following Implementation Services are provided to establish the data exchange, applications, and procedures that are necessary to provide the Services.

(i) Review Facility Diagrams, one-lines, communications, protective relaying

(ii) Perform a site visit to identify metering (Current Transformers and Potential Transformers), evaluate power supplies, identify communications equipment installation location, and assess SCADA communication options to the Gridforce control center.

(iii) Order equipment that will be installed at the [No. 4 Substation_TBD] such as: rack, router, switch, Remote Terminal Unit, Energy Management System front-end server, frequency measurement device, power distribution units, and uninterruptible power supplies.

(iv) Develop a data points list applicable to the project based on the local area network at the station, the intelligent electronic devices installed, the data requests from the incumbent interconnected Transmission Owners, and MISO's data requirements.

(v) Model the transmission facilities in the Gridforce applications; the Energy Management System, Energy Accounting, the Historian, and ICCP Communications.

(vi) Order and turn up data circuits (redundant as well as an analog line) to connect to the equipment located at the [No. 4 Substation_TBD] Substation and MISO WAN circuits.

(vii) Modify and/or develop procedures and processes for including emergency procedures, field personnel dispatch, and restoration.

(viii) Initiate and manage certification and registration procedures under the NERC rules of procedure.

(ix) Execute applicable agreements

(b) Implementation Services Exclusions. The following services are not included and are Customer's responsibility during the Implementation Term.

(i) Customer is responsible, if required, for communications between the 69 kV substations and the 161 kV substation, communications supporting protective relays, customer owned revenue quality meters, and telecom high voltage protection equipment (e.g. Positron).

(c) Access During the Implementation Term. Customer will grant to Gridforce and its agents and subcontractors such access to the Facility as is reasonably necessary and appropriate (i) for Gridforce to install, program, and test the equipment described in Section 3.1(a) or otherwise required for Gridforce to perform its obligations under this Agreement; and (ii) for Gridforce to carry out any other of its obligations under this Agreement; provided, however, that, when exercising such access rights, Gridforce (1) shall provide Customer with as much advance notice as is appropriate under the circumstances, (2) shall not unreasonably disrupt or interfere with the normal operations of the business of Customer, (3) shall work under observation by a Customer representative, and comply with the directives of such representative, and (4) shall adhere to the safety rules, procedures and polices established by Customer.

Section 3.2. <u>Local Balancing Authority and Transmission Operator Services</u>

(a) Gridforce shall perform Services as described in this Agreement and Exhibit A for the Facility with a level of accuracy, quality, completeness, timeliness, and responsiveness that is in accordance with applicable NERC Reliability Standards in effect from time to time and in a manner consistent with applicable laws and Good Utility Practice. Gridforce shall ensure that all the Services shall be performed by personnel that have the necessary knowledge, skills, experience, qualifications, rights and resources to provide and perform the Services in accordance with this Agreement and Good Utility Practice.

(b) Customer shall be responsible for performing obligations to support the Services as specified in this Agreement and Exhibit A. Gridforce shall not be in violation of this Agreement to the extent inadequate performance of the Services is caused by Customer employees, agents, representatives, contractors, or subcontractors.

(c) Gridforce shall perform Optional Services, if any, with a level of accuracy, quality, completeness, timeliness, responsiveness and cost efficiency consistent with current applicable FERC-approved NERC Reliability Standards in a manner consistent with Good Utility Practice. The terms and conditions of Optional Services shall be set forth in an appropriate Optional Services Exhibit services description, which may be agreed to subsequent to execution of the Services Agreement and shall be considered part of this Agreement, subject to the terms and conditions contained herein; provided that, any Optional Services Exhibit completed subsequent to execution of this Agreement, shall have an Optional Services Confirmation Form separately executed and the Form will become effective as of the date of such execution as if it were an amendment to the Agreement. Optional Services Exhibits may be revised from time to time, upon mutual agreement of the Parties and execution of a replacement Optional Services Confirmation Form.

Section 3.3. Gridforce Control Center and Alternate Control Center. Gridforce shall at all times during the Contract Term maintain and operate the Gridforce Control Center and Gridforce Alternate Control Center in accordance with all applicable NERC Reliability Standards.

Section 3.4. Gridforce Technology.

(a) Gridforce's Rights. Gridforce retains all rights, titles, and interests (including ownership of all patents, patent applications, including continuations, continuations-in-part, divisionals, reexaminations, and reissues, copyrights, trade secrets, trademarks, know-how, service marks and all other intellectual property rights including any derivatives, modifications or alterations thereto that are conceived, created or expressed by Gridforce or Customer ("Intellectual Property")) with respect to, and Customer shall not acquire, any interest or lien in or upon, any data, know-how, inventions, databases, tools, algorithms, architecture, user interface designs, objects, methodologies, formulas, processes, manuals, materials, reports, software (including object and source codes), documentation, training materials, hardware, equipment and networks or any other information or materials that are proprietary to Gridforce and used by Gridforce to provide Services under this Agreement, or that are related to such Services, including any enhancements, improvements, changes, modifications or additions thereto by or on behalf of Gridforce which are made and paid for by Gridforce including any enhancements, improvements, changes, modifications or additions made by Customer at the direction of, and paid for by, Gridforce under this Agreement (collectively, "Customer Modifications") during the Contract Term (collectively, the "Gridforce Technology"). In furtherance of the foregoing, Customer hereby assigns and agrees to assign in the future to Gridforce any and all of its right, title and interest in and to any Customer Modifications in and to the Gridforce Technology, including any Intellectual Property therein, during the Contract Term. At the reasonable written request of Gridforce, Customer shall promptly perform any and all other reasonable acts, at Gridforce's expense, that are necessary in order for Gridforce to perfect its interests in and to the Customer Modifications and to the Gridforce Technology.

(b) Customer's Rights To Use Gridforce Technology. Subject to the provisions of Article 14, Gridforce shall at all times during the Contract Term and during the provision of any Continuation Assistance afford Customer all necessary and appropriate rights to use the Gridforce Technology solely in connection with the matters contemplated by this Agreement, and Gridforce hereby grants, and Customer hereby accepts, on the terms and subject to the conditions of this Agreement, a fully paid-up royalty fee, non-exclusive, personal, revocable, non-assignable license for so long at this Agreement is in effect or any extension thereof to use the Gridforce Technology solely in connection with this the matters contemplated by Agreement. To the extent that the Services provided to Customer pursuant to this Agreement incorporate, use, or reference Third Party Software and Data (as defined below), Customer is granted a sublicense for the Contract Term to use the Third Party Software and Data solely in connection with this Agreement by Gridforce on the terms and conditions contained in this Agreement and as may be required by the owner of such Third Party Software and Data (each, a "Third Party Owner"). Customer's license of Third Party Software and Data is limited solely to use in conjunction with the Services provided through this Agreement. For purposes of this Agreement, "Third Party Software and Data" means the software or data available to Customer via a secure and password-protected third party software system or Gridforce Technology.

Section 3.5. Cooperation of the Parties.

(a) Reliability Standard Violations. Each Party acknowledges that the other Party may be adversely affected if it fails to comply with its respective obligations under this Agreement and such failure causes a violation of the NERC Reliability Standards applicable to the Facility. In the event of a violation of the NERC Reliability Standards applicable to the Local Balancing Authority or Transmission Operator the Parties agree that the following provisions set forth the Parties' liabilities with respect to such violation.

(i) In the event Gridforce is the sole cause of a violation of an applicable NERC Reliability Standard, Gridforce shall be responsible for and shall contest or pay all penalties, fines, fees and costs levied by the Regional Entity, NERC or any applicable Governmental Authorities associated with such violation;

(ii) In the event Customer is the sole cause of a violation of an applicable NERC Reliability Standard, Customer shall be responsible for and shall contest or pay all penalties, fines, fees and costs levied by the Regional Entity, NERC or any applicable Governmental Authorities associated with such violation;

(iii) In the event that both Parties are responsible for a violation of a NERC Reliability Standard, each Party shall be responsible for all penalties, fines, fees and cost levied by the Regional Entity, NERC or any applicable Governmental Authorities in proportion to its responsibility for causing a violation, as determined by the Facility Services Committee. If the Facility Services Committee is unable to agree on the percentage responsibility of each Party for the joint violation, the dispute shall be resolved through the remaining steps in the dispute resolution process set forth in Section 7.5.

Section 3.6. Gridforce Services Not Exclusive To Customer.

(a) Customer hereby expressly acknowledges that part of the value of the Services comes from the provision by Gridforce of services similar or identical to the Services for Persons other than Customer. Customer acknowledges that the expertise and business plan of Gridforce requires that it be able to represent multiple Persons and that the services rendered thereby are and may be beneficial to Customer.

(b) Notwithstanding the nature of the services to be performed by Gridforce under the terms of this Agreement, Customer specifically acknowledges that Gridforce is not precluded from representing or performing similar or related services for, or being employed by, Persons other than Customer, including competitors of Customer.

(c) Customer acknowledges that Gridforce from time to time has established or may establish contractual relationships with both users of power resources, transmitters of power and generators or producers of such power resources. Customer further acknowledges and accepts that Affiliates of Gridforce may, during the Contract Term, engage in energy trading, and that the existence of such activity shall not in and of itself create any conflict of interest for Gridforce in carrying out its obligations under and pursuant to this Agreement. The foregoing shall not be construed as relieving Gridforce of its obligations with respect to Customer's Confidential Information under Article 14 or any other obligations under this Agreement.

(d) Notwithstanding this Section 3.6, Gridforce agrees that in performing similar or related services for other customers, it shall do so in a non-discriminatory manner with respect to Customer, and in compliance with the FERC Standards of Conduct at all times, and will provide Customer notice of any material conflict of interest as soon as practicable

ARTICLE 4.
CONTINUING OBLIGATIONS OF THE PARTIES

Section 4.1. Access Rights.

(a) Gridforce's Access Rights. Subject to the provisions of Article 14, Customer will use commercially reasonable efforts to, or to cause the grant to, Gridforce and its agents and subcontractors such access to the Facility as is reasonably necessary and appropriate for Gridforce (i) to program, install, test, operate and maintain the Gridforce Technology, (ii) to obtain access to such information and data regarding the Facility as is reasonably necessary and appropriate for Gridforce to carry out its obligations under this Agreement, and (iii) to exercise any other of its rights and carry out any other of its obligations under or in connection with this Agreement, in each case in accordance with the terms and provisions of this Agreement; provided, however, that, when exercising such access rights, Gridforce (1) provides Customer with as much advance notice as is appropriate under the circumstances, (2) does not unreasonably disrupt or interfere with the normal operations of the business of Customer, (3) works under observation by a Customer representative and complies with the reasonable directives of such representative, (4) adheres to the safety rules and procedures and polices established by Customer and (5) acts consistent with Good Utility Practice. Customer will use commercially reasonable efforts to ensure access rights are consistently available. Gridforce shall not be in violation of this Agreement to the extent inadequate performance of the Services is caused solely by acts of Customer or the Facility that prevent Gridforce employees or agents from accessing relevant equipment or the data.

(b) Customer's Access Rights. Subject to the provisions of Articles 14, Gridforce hereby grants to Customer and its agents and subcontractors such use of the Gridforce Technology as is reasonably necessary and appropriate for Customer to perform its obligations in accordance with the terms and provisions of this Agreement and to exercise any of its rights and carry out any other of its obligations under or in connection with this Agreement (including to obtain access to such information and data regarding the Facility as is reasonably necessary and appropriate for Customer to carry out its obligations and exercise its rights under this Agreement); provided, however, that, when exercising such rights, Customer (i) does not unreasonably disrupt or interfere with the normal operations of the business of Gridforce, (iii) adheres to any rules and procedures established by Gridforce, (iv) acts consistent with Good Utility Practice and (v) does not attempt to reverse engineer, reverse compile, design around or in any other way attempt to discover the internal operations of the Gridforce Technology or to circumvent the Gridforce Technology.

(c) Term; Survival. The license granted in Section 3.4 and the access rights granted by each Party to the other Party under this Section 4.1 shall remain in effect during the Contract Term and shall survive the expiration or termination for any reason of this Agreement for so long as Gridforce is providing Services to Customer as provided for in this Agreement and for so long as reasonable, up to ninety (90) days after termination or expiration of the Contract Term, or the end of the Continuation or Transition periods to the extent necessary for each Party to exercise its rights to remove its equipment, data, technology or Intellectual Property from the premises of the other Party in accordance with the provisions of this Agreement. Notwithstanding the foregoing, should either Party decide permanently to abandon the use of any such license or access rights or any portion of any of them, the Party must send the other Party prompt written notice of such decision. In the event that a Party unilaterally revokes or terminates the other Party's access rights in breach of this Agreement, the Party whose access rights are revoked or terminated is then excused from any obligations to perform services that relate to or are dependent upon its access and that are impacted by such revocation or termination.

Section 4.2. Operation And Maintenance Of the Facility.

(a) Operation and Maintenance. Except as described in this Agreement and procedures established by and between Gridforce and Customer or Gridforce and neighboring Transmission Operators or MISO, Customer shall be solely responsible for the operation and maintenance of the Facility and shall operate and maintain the Facility in a manner which will not interfere with the operation of Gridforce's obligations under this Agreement. The Parties acknowledge and agree that Gridforce is not responsible for and shall have no obligations hereunder with respect to the operation and maintenance of the Facility.

(b) Voltage or Reactive Control Requirements. Unless otherwise agreed to by the Parties, Customer shall cause the Facility to operate voltage control equipment consistent with Good Utility Practice and in accordance with the requirements of the NERC Reliability Standards.

Section 4.3. Abnormal Operating Condition Procedures.

(a) Notification. Gridforce shall provide Customer with prompt verbal notification if Gridforce becomes aware of any Abnormal Operating Condition which may reasonably be expected to affect Gridforce's operations or the Facility, and Customer shall provide Gridforce with prompt verbal notification if it becomes aware of any Abnormal Operating Condition regarding the Facility which may reasonably be expected to affect Gridforce's operations.

(b) Customer Facility Isolation Rights. Customer reserves the right, consistent with Good Utility Practice, to remove the Facility from service if, in its good faith judgment, it believes that continued parallel operation is creating or contributing to an Abnormal Operating Condition regarding the Facility.

(c) Mitigation Or Elimination. To the extent necessary, each Party agrees to cooperate and coordinate with the other Party in taking whatever reasonable corrective measures as are necessary to mitigate or eliminate the Abnormal Operating Condition, provided such measures are consistent with Good Utility Practice and do not require operation of the Facility outside the Facility Operating Limits.

Section 4.4. Modifications to Gridforce Technology.

(a) Modifications Not Required. Unless otherwise agreed to by the Parties or otherwise required by applicable Governmental Rules or the NERC Reliability Standards applicable to the Facility, Gridforce shall not be required at any time to upgrade or otherwise modify the Gridforce Technology; provided, however, that Gridforce agrees, at Customer 's expense, to make any additions, modifications, or replacements to the Gridforce Technology that are requested by Customer in writing so long as such additions, modifications, or replacements are consistent with Good Utility Practice and NERC footprint expansion procedures or processes.

(b) GEM Modification Rights. Subject to the provisions of Section 4.5, Gridforce, in its reasonable discretion, and subject to the terms and conditions of this Agreement governing access to the Facility, may undertake additions, modifications, or replacements of the Gridforce Technology during the Contract Term, so long as such additions, modifications, or replacements are consistent with the applicable Reliability Standards.

(c) Notification Regarding Modifications. If any additions, modifications, or replacements of the Gridforce Technology might reasonably be expected to negatively affect the operation of the Facility, Gridforce shall provide one hundred and twenty (120) days' written notice to Customer prior to undertaking any such additions, modifications, or replacements (unless Good Utility Practice requires Gridforce to undertake such additions or modifications prior to the expiration of the ninety (90) day period, in which case Gridforce shall provide Customer such advance written notice as is reasonably practicable under the circumstances) and conduct such work at mutually agreeable times. If Customer objects to such additions, modifications, or replacements Customer must request a mitigation plan from the Facility Services Committee within 10 days or receipt of notice of the addition, modification or replacement. If the Facility Services Committee has not unanimously reached an agreement on the mitigation plan within thirty (30) days, (i) Gridforce may at its sole discretion proceed with the addition, modification or replacement required or (ii) Customer must terminate this Agreement, prior to the effective date of the applicable Governmental Rule with prompt written notice to Gridforce specifying the expected date of termination and payment of the Termination Fee.

Section 4.5. Responsibility for Section 4.4(b) Modification Costs.

(a) Gridforce acknowledges and agrees that the majority of additions, modifications or replacements undertaken pursuant to Section 4.4(b) will be paid for solely by Gridforce. However, in the event that additions, modifications or replacements undertaken pursuant to Section 4.4(b) are required due to change in applicable Governmental Rules, NERC or Regional Entity standard, Customer shall be responsible for an equitable, pro rata share of the actual, documented and reasonable costs and expenses incurred by Gridforce for such additions, modifications or replacements provided that Gridforce has notified Customer in writing and in advance of incurring such costs and expenses. For purposes of this Section 4.5(a), Customer's equitable, pro rata share shall include consideration of the number of Gridforce customers that are affected by the modification, to which Gridforce is providing services at the time such additions, modifications, or replacements are made. If Customer objects to such modification prior to implementation of the change, (i) Gridforce may at its sole discretion proceed with the addition, modification or replacement required or (ii) Customer must terminate this Agreement, prior to the effective date of the applicable Governmental Rule with prompt written notice to Gridforce specifying the expected date of termination and payment of the Termination Fee.

(b) In the event that the additions, modifications or replacements to Gridforce Technology are not required by applicable Governmental Rules, but are required as a result of any modification by Customer or the Facility, Customer will reimburse Gridforce for the costs and expenses incurred by Gridforce in connection with the installation and construction of such additions, modifications or replacements.

(c) For any other additions, modifications and replacements undertaken to Gridforce Technology for which Customer is not specifically responsible hereunder, Gridforce shall be responsible for the costs and expenses associated with such additions, modifications or replacements to Gridforce Technology.

Section 4.6. Modifications to the Facility Network or Exhibit A.

(a) Modifications Permitted. Customer, in its discretion and at its sole cost and expense, may undertake additions, modifications or replacements, or may cause the undertaking of additions, modifications or replacements, to the Facility network, so long as such additions, modifications or replacements do not directly impact Gridforce's ability to provide the Services pursuant to this Agreement; provided, however, that if any such additions, modifications or replacements undertaken by Customer pursuant to this Section 4.6(a) are required as a result of any modification by Gridforce of the Gridforce Technology permitted under Section 4.4(b) that is not required by applicable Governmental Rules or as a result of any modification by Customer, Gridforce will reimburse Customer for the actual, documented, reasonable costs and expenses incurred by Customer in connection with the installation and construction of such additions, modifications or replacements.

(b) Notification Regarding Modifications. If any additions, modifications or replacements undertaken by Customer would reasonably be expected to affect Gridforce's ability to satisfy its obligations under this Agreement, Customer shall notify Gridforce in writing at least ninety (90) days in advance of undertaking such additions, modifications or replacements (unless Good Utility Practice requires Customer to undertake such additions, modifications or replacements in a shorter duration, in which case Customer shall provide Gridforce such advance written notice as is reasonably practicable under the circumstances) and shall conduct work at mutually agreeable times.

(c) Gridforce Proposed Modifications to Exhibit A. Gridforce shall notify Customer of any proposed additions or modifications needed to Exhibit A that affect Customer, that Gridforce believes are reasonably necessary and appropriate for Gridforce to perform its obligations under this Agreement in accordance with applicable Governmental Rules, along with the reasonable time period within which Gridforce believes that such additions or modifications should be effective. Unless otherwise agreed by the Parties, and if in Customer's reasonable opinion such additions or modification are consistent with Good Utility Practice, Customer shall be responsible for any and all actual, documented and reasonable costs and expenses incurred for and in connection with these additions or modifications. Customer may respond with commercially reasonable objections to such additions or modifications, including the extent to which such additions or modifications are reasonable and appropriate. If Customer disagrees with or objects to the appropriateness or necessity of any additions or modifications proposed by Gridforce pursuant to this Section 4.6(c), Customer must request a mitigation plan from the Facility Services Committee within thirty (30) days of receipt of the proposed addition or modification. If the Facility Services Committee has not unanimously reached an agreement on a mitigation plan within thirty (30) days, (i) Gridforce may at its sole discretion proceed with the addition, modification or replacement required due to a material change to applicable Governmental Rules or NERC Reliability Standard or (ii) Customer must terminate this Agreement, prior to the effective date of the applicable Governmental Rule or NERC or Reliability Standard, upon prompt written notice to Gridforce specifying the expected date of termination and payment of the Termination Fee.

Section 4.7. Information and Record-Keeping Obligations.

(a) Information Obligations.

(i) Either Party may request that the other Party make available such information and data required by this Agreement as the requesting Party may reasonably require from the other Party to; (1) carry out the requesting Party's responsibilities under this Agreement; and (2) satisfy reporting obligations that the requesting Party may have to any Governmental Authority pursuant to the requesting Party's obligations under this Agreement, excluding Gridforce Technology. In the event of any such request, the Party to which the request is made shall use reasonably efforts to promptly make available any such requested information and data.

(ii) Each Party's right to request information and data under this Section 4.7(a) shall be subject to Article 14 of this Agreement and the limitation that neither Party may use information or data provided by the other Party for any purpose other than as specified in this Section 4.7(a).

(b) Record-Keeping Obligations. Each Party shall maintain such records as are required by (i) any applicable Governmental Authority pursuant to each party's obligations under this Agreement, and (ii) this Agreement, and (iii) all data, documents, or other materials relating to or substantiating any charges, costs or expenses payable or reimbursable by the other Party under and in accordance with the applicable requirements or rules or for a period of three (3) years from and after the date on which the records are created or assembled for purposes of this Agreement. Neither Party shall use the accounts or records of the other Party without the express written consent of the other Party unless such use is permitted by this Agreement or required by Governmental Rule, provided that, if permitted by law, such use as is required for Governmental Rule shall not occur until after the other Party has been notified.

Section 4.8. Telemetry. Gridforce shall provide Customer with all metering and telemetry data that is available to Gridforce and stored in the Gridforce historian upon request within a reasonable time. In the event that any metering equipment installed at the Facility fails to register data, the delivery or receipt of electricity from the Facility shall be determined from the best available data, as agreed by Gridforce and any affected neighboring Local Balancing Authority.

Section 4.9. Metering Operation and Maintenance. Customer shall be responsible under this Agreement for operating and maintaining the metering equipment at the Facility in accordance with Good Utility Practices unless the neighboring Local Balancing Authority operates and maintains the metering equipment.

Section 4.10. Operating Representatives. Gridforce and Customer shall each designate a single individual in their respective organizations (the "Operating Representative") to coordinate all operational information to be transmitted between the Parties consistent with this Agreement. Each Party may change its Operating Representative from time to time by providing notice within a reasonable period of time in accordance with the requirements of this Agreement.

Section 4.11. Facility Services Committee.

(a) As a means of securing effective and timely cooperation with respect to the activities hereunder and as a means of dealing on a prompt and orderly basis with various issues that may arise in connection with Services coordination and operation under changing conditions, the Parties shall establish a Facility Services Committee (the "Facility Services Committee"), comprising the Facility Services Committee Representatives. The Facility Services Committee may, upon mutual agreement, from time to time meet or consult with representatives as appropriate from a Regional Entity and/or NERC which shall serve solely an advisory function. The sole responsibilities of the Facility Services Committee shall be, with respect to the Services provided hereunder:

(i) to review procedures and standard practices, consistent with the provisions of this Agreement, for the guidance of operating employees as to matters affecting transactions under this Agreement;

(ii) to review any operating procedures required in connection with this Agreement;

(iii) to review and approve all changes to the protocols that pertain to the Facility;

(iv) to review and recommend as necessary the types and arrangement of equipment for intersystem communication facilities to enhance transactions and benefits under this Agreement;

(v) to review potential changes to or an expansion of the Facility or the scope of services provided by Gridforce;

(vi) to review the appropriateness or necessity of any additions or modifications proposed by Gridforce pursuant to Section 4.6(c); and

(vii) to do such other things and carry out such duties as specifically required or authorized by this Agreement; provided, however, that the Facility Services Committee shall have no authority to amend or modify any provision of this Agreement except Exhibit A or procedures which must be modified by the Facility Services Committee to comply with requirements established by NERC, if such modification is consistent with the express terms of this Agreement, is reduced to writing and is signed by each Facility Services Committee Representative.

(b) Gridforce and Customer shall each select one (1) representative (the "Facility Services Committee Representative") for the Facility Services Committee. Unless and until a Party provides notice to the contrary, its Facility Services Committee Representative shall be the Operating Representative it designated pursuant to Section 4.9. In addition, Gridforce and Customer shall each select an alternate representative for the Facility Services Committee to act in the absence of its Facility Services Committee Representative. Each Party shall, on or before the Effective Date, in accordance with the requirements of this Agreement, give notice to the other Party of the name of its Facility Services Committee Representative and alternate representative. Each Party shall, in accordance with the requirements of this Agreement, also give notice to the other Party of any change of its Facility Services Committee Representative or alternate representative, as soon as possible but no more than thirty (30) days after the effectiveness of any such change. Each Party's Facility Services Committee Representative shall be authorized to act on its behalf with respect to those committee responsibilities provided herein. Each Facility Services Committee Representative shall be entitled to bring one or more additional employee or subcontractor of such Party to any meeting of the Facility Services Committee in order to provide any necessary or appropriate technical support.

(c) The Facility Services Committee shall not be entitled to take any action or make any recommendation without the unanimous written consent of all of the Facility Services Committee Representatives.

ARTICLE 5.
FEES AND COSTS

Customer shall compensate GEM for Implementation Services, Local Balancing Authority Services and Transmission Operator Services, and Optional Services provided under this Agreement in accordance with the terms and conditions of this Agreement and Exhibit C.

ARTICLE 6.
REPRESENTATIONS, WARRANTIES, COVENANTS AND CONDITIONS

Section 6.1. Representations and Warranties of The Parties. Each Party, with respect to itself, hereby represents and warrants to the other Party as of the date hereof and as of the Effective Date as follows:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation and is qualified to conduct its business in those jurisdictions necessary to perform this Agreement;

(b) the execution, delivery and performance of this Agreement are within its statutory and corporate or organizational powers, have been duly authorized by all necessary action and do not conflict with or result in a breach of or default (with or without notice or lapse of time or both) under any of the terms or conditions in its governing documents or any contract to which it is a party or any Governmental Rule applicable to it;

(c) this Agreement has been duly executed and delivered on its behalf by a duly authorized representative of such Party;

(d) this Agreement constitutes a legal, valid and binding obligation of such Party enforceable against it in accordance with its terms, subject to bankruptcy, insolvency, reorganization, moratorium or other Governmental Rules affecting creditors' rights generally, and with regard to equitable remedies, subject to equitable defenses and the discretion of the court before which proceedings to obtain such remedies may be pending;

(e) there are no bankruptcy, insolvency, reorganization, receivership or other arrangement proceedings pending or being contemplated by it, or to its knowledge threatened against it; and

(f) there are no suits, proceedings, judgments, rulings or orders by or before any Governmental Authority that materially adversely affect such Party's ability to perform this Agreement.

Section 6.2. No Other Representations and Warranties. Each Party acknowledges that it has entered into this Agreement based solely upon the express representations and warranties set forth in this Agreement

Section 6.3. Disclaimer of Warranties. EXCEPT AS EXPRESSLY SET FORTH HEREIN, EACH PARTY EXPRESSLY NEGATES ANY OTHER REPRESENTATION OR WARRANTY, WRITTEN OR ORAL, EXPRESS OR IMPLIED, INCLUDING ANY

REPRESENTATION OR WARRANTY WITH RESPECT TO CONFORMITY TO MODELS OR SAMPLES, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE.

ARTICLE 7. EVENTS OF DEFAULT AND REMEDIES

Section 7.1. Events of Default. An "Event of Default" means any of the following:

(a) the failure by a Party (the "Defaulting Party") to make, when due, any payment for undisputed amounts required under this Agreement, if such failure is not cured within twenty (20) Business Days after written notice thereof from the Non-Defaulting Party; or

(b) any material representation or warranty made by a Party (the "Defaulting Party") in this Agreement shall prove to have been false or misleading in any material respect on the date made; or

(c) any failure by the Defaulting Party to perform its obligations under this Agreement or comply with any covenant set forth in this Agreement in any material respect, if such failure is not excused by Force Majeure or cured within thirty (30) days after written notice thereof from the Non-Defaulting Party or, if such failure cannot be completely corrected or cured within thirty (30) days, if the Defaulting Party fails to (1) commence within such thirty (30) day period, and sustain continuously thereafter, diligent efforts to correct or cure such failure, and (2) completely correct or cure such failure within ninety (90) days after written notice thereof from the Non-Defaulting Party.

Section 7.2. Remedies upon an Event of Default by Gridforce. If an Event of Default with respect to Gridforce occurs and is continuing without cure for thirty (30) consecutive days after written notice by Customer, Customer may:

(a) effective immediately upon written notice to Gridforce, terminate this Agreement without incurring any penalties (including the Termination Fee), without prejudice to Owner's rights under Section 2.6; and/or

(b) take whatever action at law or in equity, consistent with the provisions of this Agreement, as may appear necessary or desirable to enforce the performance or observance of any rights, remedies, obligations, agreements, or covenants under this Agreement.

Section 7.3. Remedies upon an Event of Default by Customer. If an Event of Default with respect to Customer occurs and is continuing without cure for thirty (30) consecutive days after written notice by Gridforce, Gridforce may:

(a) provide notice of termination of this Agreement and collect penalties, fines, fees and cost paid by Gridforce; and/or

(b) take whatever action at law or in equity, consistent with the provisions of this Agreement, as may appear necessary or desirable to enforce the performance or observance of any rights, remedies, obligations, agreements, or covenants under this Agreement.

Section 7.4. Remedies Exclusive. The remedies available to Customer under this Agreement in respect of or in consequence of (i) any breach of contract, (ii) any negligent act or omission, (iii) death or personal injury, or (iv) loss of or damage to any property, are to the exclusion of any other remedy that Customer may have against Gridforce under applicable law.

Section 7.5. Dispute Resolution. Any claim controversy or dispute arising out of, relating to, or in connection with this Agreement, including the interpretation, validity, termination or breach hereof, shall be submitted to the Facility Services Committee for resolution. If the Facility Services Committee is unable to resolve the disagreement through mutual agreement within ten (10) Business Days of the dispute being referred to them, then the dispute shall be referred to an executive of each Party authorized to resolve such dispute. If such executives are unable to resolve the dispute within twenty (20) Business Days, or any other mutually agreeable time period, each Party may pursue resolution of the dispute through any action at law or in equity, consistent with the provisions of this Agreement, available to it.

ARTICLE 8.
INDEMNITY

Section 8.1. Mutual Indemnity.

(a) EACH PARTY (THE "INDEMNIFYING PARTY") SHALL INDEMNIFY, DEFEND AND HOLD HARMLESS THE OTHER PARTY AND ITS AFFILIATES, REPRESENTATIVES AND INVITEES (COLLECTIVELY, THE "INDEMNIFIED PARTIES") FROM AND AGAINST ANY AND ALL SUITS, ACTIONS, LIABILITIES, LEGAL PROCEEDINGS, CLAIMS, FINES, PENALTIES, DEMANDS, LOSSES, COSTS AND EXPENSES OF WHATSOEVER KIND OR CHARACTER, INCLUDING REASONABLE ATTORNEYS' FEES AND EXPENSES (COLLECTIVELY, "LOSSES") TO THE EXTENT THAT THE SAME ARISES OUT OF OR RESULTS FROM (i) ANY NEGLIGENT ACTS OR OMISSIONS BY THE INDEMNIFYING PARTY OR ITS SUBCONTRACTORS OR THEIR RESPECTIVE AGENTS OR EMPLOYEES THAT CAUSE INJURY OR DEATH TO THIRD PARTIES OR LOSS OF OR DAMAGE TO THE PROPERTY OF THIRD PARTIES, (ii) ANY WILLFUL MISCONDUCT OR WILLFUL BREACH OF THIS AGREEMENT ON THE PART OF THE INDEMNIFYING PARTY OR ITS RESPECTIVE SUBCONTRACTORS OR ITS RESPECTIVE AGENTS OR EMPLOYEES IN THE PERFORMANCE OF ITS EXPRESS OBLIGATIONS ARISING UNDER THIS AGREEMENT, OR (iii) ANY PENALTIES, FINES, FEES AND COSTS LEVIED ON THE OTHER PARTY BY THE REGIONAL ENTITY, NERC OR ANY APPLICABLE GOVERNMENTAL AUTHORITY FOR WHICH THE INDEMNIFYING PARTY IS RESPONSIBLE HEREUNDER.

(b) NOTWITHSTANDING SECTIONS 8.1(a), WHEN ANY OBLIGATION FOR INDEMNIFICATION RESULTS FROM JOINT OR CONCURRENT NEGLIGENCE, OR WILLFUL MISCONDUCT OF BOTH PARTIES, SUCH PARTIES' DUTY OF INDEMNIFICATION SHALL BE IN PROPORTION TO EACH SUCH PARTY'S ALLOCABLE SHARE OF JOINT OR CONCURRENT NEGLIGENCE, OR WILLFUL MISCONDUCT.

Section 8.2. Notice. An Indemnified Party must promptly, upon its discovery of facts or circumstances giving rise to a claim for indemnification, give written notice thereof to the Indemnifying Party. To the extent that the Indemnifying Party is or will be actually and materially prejudiced as a result of the failure of the Indemnified Party to provide timely notice, the Indemnifying Party's liability shall be reduced proportionate to such prejudice.

Section 8.3. Amount of Losses. The amount of losses shall be computed net of any related recoveries to which the Indemnified Party is entitled under insurance policies, or other payments received or currently receivable from third parties.

Section 8.4. Workers' Compensation. In furtherance of the foregoing indemnification and not by way of limitation thereof, the Indemnifying Party hereby waives any defense it otherwise might have under applicable workers' compensation laws. In claims against any Indemnified Party by any representative of the Indemnifying Party, the indemnification obligation under this Article 8 shall not be limited by a limitation on amount or type of damages, compensation or benefits payable by or for the Indemnifying Party or a subcontractor under workers' or workmen's compensation acts, disability benefit acts or other employee benefit acts.

Section 8.5. Survival. For a period of one (1) year, the obligations contained herein shall survive the expiration or termination of this Agreement.

ARTICLE 9.
LIMITATION OF LIABILITY; MITIGATION OF DAMAGES

Section 9.1. Limitation Of Liability.

(a) Limitations of Liability. EXCEPT AS SPECIFICALLY PROVIDED FOR IN THIS AGREEMENT, A PARTY, INCLUDING A THIRD PARTY OWNER, WILL NOT BE LIABLE TO THE OTHER PARTY FOR ANY INDIRECT, INCIDENTAL, PUNITIVE, SPECIAL OR CONSEQUENTIAL DAMAGES OF ANY KIND OR NATURE WHATSOEVER ARISING OUT OF PERFORMANCE OR NON-PERFORMANCE OF THIS AGREEMENT, WHETHER BY STATUTE, IN TORT OR CONTRACT, WARRANTY, STRICT LIABILITY, OR ANY OTHER THEORY OF RECOVERY. WITHOUT LIMITING THE FOREGOING, THE MAXIMUM AMOUNT OF GRIDFORCE'S LIABILITY, IF ANY, ARISING FROM ALL CLAIMS, LAWSUITS, ACTIONS OTHER LEGAL PROCEEDINGS BY CUSTOMER, ANY CUSTOMER REPRESENTATIVE, OR ANY OTHER PERSON OR ENTITY ARISING OUT OF OR IN CONNECTION WITH GRIDFORCE'S PERFORMANCE OR NON-PERFORMANCE UNDER THIS AGREEMENT SHALL BE 100% OF THE MONTHLY SERVICE FEES PAYABLE IN THE CONTRACT YEAR IN WHICH SUCH LIABILITY AROSE.

(b) Limitations of Liability, Duty to Mitigate. Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this Agreement; provided, however, that nothing in this Agreement shall be construed to require a Party to settle any strike or labor dispute in which it may be involved.

Section 9.2. Limitations of Liability, Survival. The provisions of this Article 9 shall survive expiration or termination of this Agreement.

ARTICLE 10.
BILLING AND PAYMENT; AUDIT RIGHTS

Section 10.1. Billing And Payment.

(a) On or before the tenth (10^{th}) day of each calendar month during the Implementation Term Gridforce shall render to Customer (by regular mail, facsimile or other means permitted under Article 13) an invoice setting forth the Implementation Services Fee due for the previous calendar month pursuant to Exhibit C. Payment of any undisputed amounts contained in such invoice shall be made by Customer to Gridforce in immediately available funds at the invoice address provided in Exhibit B within thirty (30) days of receipt of the invoice; provided that, if such due date is not a Business Day, payment shall be due on the next Business Day following such date.

Any disputed payments shall be resolved in accordance with Section 7.5 of this Agreement and upon resolution any payment due to Gridforce shall be made promptly thereafter. In the event that the netted amount of any invoice results in a payment being due to Customer from Gridforce, Customer shall notify Gridforce of same and have the option to have such amount paid to it subject to the terms of this Section 10.1 from the date Gridforce receives such notification, or applied against any amounts Customer may owe Gridforce for the next calendar month. Late payments shall accrue interest, for each day from the due date to the date of the payment, at a rate equal to the effective prime commercial lending rate for such day as published in the Wall Street Journal under "Money Rates;" provided, the interest rate shall never exceed the maximum lawful rate permitted by applicable Governmental Rule ("Interest").

(b) On or before the tenth (10^{th}) day of each calendar month during the Services Term, Gridforce shall render to Customer (by regular mail, facsimile or other means permitted under Article 13) an invoice setting forth the Monthly Services Fee and, if applicable, the Optional Services Fee and the Annual Facility Maintenance Charge due for the next calendar month pursuant to Exhibit C; and the total amount of any other amounts, if any, due to Gridforce under this Agreement for the immediately preceding calendar month. Payment of any undisputed amounts contained in such invoice shall be made by Customer to Gridforce in immediately available funds at the invoice address provided in Exhibit B within thirty (30) days of receipt of the invoice; provided that, if such due date is not a Business Day, payment shall be due on the next Business Day following such date. Any disputed payments shall be resolved in accordance with Section 7.5 of this Agreement and upon resolution any payment due to Gridforce shall be made promptly thereafter. In the event that the netted amount of any invoice results in a payment being due to Customer from Gridforce, Customer shall notify Gridforce of same and have the option to have such amount paid to it subject to the terms of this Section 10.1 from the date Gridforce receives such notification, or applied against any amounts Customer may owe Gridforce for the next calendar month. Late payments shall accrue interest, for each day from the due date to the date of the payment, at a rate equal to the effective prime commercial lending rate for such day as published in the Wall Street Journal under "Money Rates;" provided, the interest rate shall never exceed the maximum lawful rate permitted by applicable Governmental Rule ("Interest").

Section 10.2. Audits.

(a) Gridforce shall keep accounts and records of all costs and expenses incurred, in the performance of its obligations under this Agreement. Customer shall have the right, at its expense, to audit any costs, payments, or other supporting documentation pertaining to transactions under this Agreement to determine the accuracy of payments provided to the other Party under this Agreement; provided that (a) all costs billed pursuant to this Agreement shall be subject to audit for a period of one (1) year following the issuance of an invoice therefore; (b) no adjustment for any invoice shall be made unless an objection was made to such invoice no later than one (1) year following the issuance of an invoice therefore; and (c) a Party may not conduct more than one (1) payment accuracy audit per calendar year, unless the audit is requested by a Governmental Authority or unless Customer, acting in good faith, identifies in writing irregularities meriting an audit. Audits shall take place during normal business hours and at the offices where such accounts and records are maintained, unless otherwise agreed upon by the Parties. Customer agrees to use commercially reasonable efforts and reasonably work with Gridforce on the timing and scheduling of any audits undertaken by Customer. To the extent that audited information includes Confidential Information (as the term is defined in Article 14), the auditing Party shall comply with the confidentiality provisions of this Agreement.

(b) Audits shall be performed in a manner intended to minimize disruption to the Parties' respective businesses or the Parties' ability to perform its respective obligations under this

Agreement. All such audits and verifications may be conducted during the term of this Agreement and for a period of ninety (90) days after the termination or expiration of this Agreement or such longer period required by law or regulations applicable to the auditing party. To the extent that audited information includes Confidential Information, the auditing Party shall comply with the confidentiality provisions of this Agreement.

(c) Gridforce shall assist Customer's auditors (including internal audit staff), inspectors, regulators, consultants, and other representatives as is reasonably required. Gridforce shall cooperate fully with Customer or its designees in connection with audit functions and with regard to examinations by regulatory authorities and shall, on a timely basis, furnish each with information requested. Customer and Customer's designees acknowledge and agree that Gridforce is subject to confidentiality agreements with third parties, laws and regulatory requirement, NERC and Regional Entity standards Gridforce's security and safety policies regarding access that are in place at the time of the audit that may impact Gridforce's ability to assist, release information or allow examination by Customer or its designees.

ARTICLE 11.
ASSIGNMENT; BINDING EFFECT

Section 11.1. Assignment. Neither Party shall assign this Agreement or any of its rights or obligations hereunder (whether by operation of law or otherwise) to any person or entity without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. This Agreement shall be binding on and inure to the benefit of the Parties thereto, their successors and permitted assigns.

Section 11.2. Financing Assignments. Notwithstanding anything to the contrary in Section 11.1, either Party may, without the prior written consent of the other Party but with prior written notice assign its rights to receive payment (but not its obligations) under this Agreement to any entity(ies) or institution(s) for the purposes of financing or refinancing the development, design, construction, or operation of the assigning Party's facilities.

Section 11.3. Party to Remain Responsible. No assignment permitted under this Article 11 shall relieve the assigning Party from its obligations, duties, liabilities, or financial responsibility hereunder unless and until (a) the assignee(s) agrees in writing to assume the obligations, duties, liabilities, and financial responsibilities of the assigning Party and in connection therewith cures any then existing payment defaults of the assigning Party and any then existing performance defaults that are capable of cure under this Agreement and (b) the non-assigning Party reasonably determines that the assignee(s) is no less technically and financially capable of performing its obligations and duties under this Agreement than was the assigning Party.

ARTICLE 12.
FORCE MAJEURE

Section 12.1. Notice of Claim of Force Majeure. If either Party is rendered unable by an event of Force Majeure to carry out, in whole or in part, its obligations under this Agreement, such Party shall, as soon as reasonably practicable after the occurrence of the event, give the other Party notice thereof, including full details of the Force Majeure event, the date of its commencement, the anticipated duration, if ascertainable, the performance of the Party claiming Force Majeure that is prevented by the Force Majeure event, and the actions being taken to mitigate the effects of the Force Majeure event.

Section 12.2. Performance Excused. During the pendency of the Force Majeure event but for no longer period, the Party claiming Force Majeure shall be excused, to the extent provided for in this Agreement, from the obligations under this Agreement that are prevented by the Force Majeure event.

Section 12.3. Mitigation. The Party claiming Force Majeure shall use commercially reasonable efforts to remedy the Force Majeure event with all reasonable dispatch; provided, however, that neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest, it being understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be entirely within the discretion of the Party having such dispute.

Section 12.4. Payment Obligations.

(a) If there is a Force Majeure event affecting Gridforce and Gridforce's ability to provide Services: (i) Customer shall be relieved from paying all fees payable hereunder during the pendency of the Force Majeure event (which fees shall be pro-rated for the period of time during which the relevant services were unavailable) and (ii) if the Force Majeure event exceeds sixty (60) days, this Agreement may be terminated on at least ninety (90) days' notice with no Termination Fee.

(b) If there is a Force Majeure event affecting Customer or the Facility that adversely affects Gridforce's ability to provide the Services, then such event shall not relieve Customer of its obligation to make payments under this Agreement; provided, however, that if the Force Majeure event exceeds sixty (60) days, this Agreement may be terminated on at least ninety (90) days' notice with no Termination Fee.

Section 12.5. Notice of Ability to Resume Performance. As soon as the Party claiming Force Majeure is able to resume performance of its obligations excused as a result of the occurrence, it shall give prompt written notification thereof to the other Party.

ARTICLE 13.
NOTICES

Section 13.1. All notices, requests, statements or payments shall be made to the addresses and persons specified in Exhibit B hereto. All notices, requests, statements or payments shall be made in writing, except (a) where this Agreement expressly provides that notice may be made orally and (b) notices of an operational nature may be provided by telephone, facsimile, or e-mail; provided, that if any such written notice is provided by facsimile or e-mail, it shall be confirmed immediately by telephone. Notices required to be in writing shall be delivered by hand delivery, overnight delivery, facsimile, or e-mail. A Party may change its address or the persons specified in Exhibit B by providing notice of the same in accordance herewith.

ARTICLE 14.
CONFIDENTIALITY OBLIGATIONS

Section 14.1. Confidential Information Defined.

(a) Information Deemed Confidential. For purposes of this Agreement, "Confidential Information" means (i) all information, including trade secrets and proprietary information (including financial information and information regarding contractual relationships, business and pricing forecasts, licensing and regulatory compliance techniques, business processes, sales, and marketing plans), in whatever form, or technology, including Gridforce Technology, or information related to technology or Gridforce Technology, that is furnished by either Party (the "Disclosing Party") or its representatives to the other Party (the "Recipient Party") or its representatives, and that the Disclosing Party or any of its representatives designate as confidential or should reasonably be viewed as confidential by the Recipient Party; (ii) all information of a commercial nature or which concerns the cost, design, operation, maintenance, scheduling, output and other economic aspects of the Gridforce or the Customer or a Customer Facility, whether exchanged orally or in written or electronic form; (iii) all information that is metered or telemetered with respect to the Balancing Authority Area; (iv) the substance of any discussions or negotiations between the Disclosing Party and the Recipient Party or any representatives relating to any of the foregoing; and (v) all notes, reports, documents, analyses, compilations, forecasts, studies, synopses, and other materials of a Party or any of its representatives that reflect, interpret, evaluate, or are derived from any of the foregoing; and (vi) all information obtained by Customer from Gridforce relating to this Agreement, in whatever form.

(b) Information Not Deemed Confidential. Confidential Information does not include information which: (i) is or becomes generally available to the public other than as a direct or indirect result of an intentional or inadvertent disclosure by the Recipient Party or any of its representatives, or anyone to whom the Recipient Party or any of its representatives transmits the information; (ii) was available to the Recipient Party prior to its disclosure to the Recipient Party by the Disclosing Party or any of the Disclosing Party's representatives, provided that such information is not known to the Recipient Party to be subject to another confidentiality agreement with, or other obligation of secrecy to, the Disclosing Party or another party; (iii) becomes available to the Recipient Party from a source other than the Disclosing Party or any of the Disclosing Party's representatives, provided that such source is not known to the Recipient Party to be subject to another confidentiality agreement with, or other obligation of secrecy to, the Disclosing Party or another party; or (iv) is independently developed by the Recipient Party, other than in connection with this Agreement.

Section 14.2. Nondisclosure Of Confidential Information. Except as set forth in this Section 14.2 and in Section 14.3, the Recipient Party shall not disclose any Confidential Information to any Person other than as permitted hereby, and shall safeguard each and all of the Confidential Information from unauthorized disclosure in accordance with the terms of this Article 14.

(a) The Recipient Party may disclose Confidential Information to any of its Affiliates, and any of its or any such Affiliate's representatives, but only if such Persons need to know the Confidential Information for purposes permitted by this Agreement and are notified of the confidential nature of the information; provided, however, that Gridforce may not disclose Confidential Information to those employees of any Affiliates of Gridforce that are engaged in developing, owning or operating bulk electric system electric generation facilities or trading in energy commodities. Each Party agrees to be responsible for any unauthorized disclosure of such information by such Persons.

(b) The Recipient Party may disclose Confidential Information to its representatives who need to know such information in connection with the performance of this Agreement. The Recipient Party agrees to notify such Persons of the confidential nature of such information and to be responsible for any unauthorized disclosure of such information by such Persons.

(c) Gridforce may disclose Confidential Information to any Balancing Authority, Transmission Operator, Reliability Coordinator or representative who need to know such information in connection with the performance of this Agreement. Gridforce agrees to notify such Persons of the confidential nature of such information, if the sharing of the information is not covered by non-disclosure agreements, and to be responsible for any unauthorized disclosure of such information by such Persons.

Section 14.3. Disclosure to Regional Entity, NERC, and Governmental Authorities. Confidential Information may be disclosed to a Regional Entity, NERC and any Governmental Authority requesting such Confidential Information, provided that unless the disclosure is the result of a normal compliance enforcement and monitoring activity, to the extent practicable and legally permissible, (i) prior to disclosure, the Recipient Party shall inform the Disclosing Party of the substance of any requirements so that the Disclosing Party may take whatever action it deems appropriate, including intervention in any proceeding and the seeking of an injunction or other protective relief to prohibit such disclosure, and (ii) such disclosure is limited to the extent necessary to comply with such Governmental Authority.

Section 14.4. Remedies. Any violation of Article 14 of this Agreement may cause irreparable harm to the Disclosing Party. Accordingly, the Disclosing Party shall be entitled to seek injunctive relief enjoining and restraining any violation.

ARTICLE 15.
MISCELLANEOUS

Section 15.1. Entire Agreement; Amendments. This Agreement constitutes the entire agreement between the Parties. Except for any matters, which, in accordance with the express provisions of this Agreement, may be resolved by oral agreement between the Parties, and no amendment, modification or change herein shall be enforceable unless reduced to writing and executed by both Parties.

Section 15.2. Governing Law. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY FEDERAL LAW WHERE APPLICABLE, AND, WHEN NOT IN CONFLICT WITH OR PREEMPTED BY FEDERAL LAW, SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO ITS CONFLICTS OF LAW PRINCIPLES. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED. Each party to this Agreement acknowledges that it has been induced to execute and deliver, or change its position in reliance upon the benefits of, this Agreement by, among other things, the mutual waivers and certifications in this Section.

Section 15.3. Non-Waiver. No waiver by either Party of (a) the performance of any provision of this Agreement by the other Party, (b) any one or more Event of Default by the other Party in the performance of any of the provisions of this Agreement, or (c) any of such Party's rights under this Agreement shall be construed as a waiver of any other performance, Event of Default, or rights, whether of a like kind or different nature.

Section 15.4. Severability. Except as otherwise provided in this Agreement, any provision or article declared or rendered unlawful by a Governmental Authority with jurisdiction over the Parties, or deemed unlawful because of a change in Governmental Rule, shall not affect the validity, legality, and enforceability of the remaining provisions and articles of this Agreement.

Section 15.5. PUHCA Compliance.

(a) In the event that Gridforce reasonably determines that it may become subject to the provisions of PUHCA 2005, as a public utility company as a result of its rights or obligations under this Agreement, then Gridforce shall promptly notify Customer in writing, prior to initiating the terms of this Section, and Gridforce and Customer shall negotiate in good faith for a reasonable period of time to amend this Agreement to prevent or remedy such applicability of PUHCA 2005 so that Gridforce does not become or will no longer be subject to the provisions of PUHCA 2005 as a public utility company; provided, however, that Gridforce shall have the right to immediately or at any time thereafter take any action specifically required by the FERC with respect to the provision of Services so that Gridforce does not become or will no longer be subject to the provisions of PUHCA 2005 as a public utility company. If the Parties are unable to mutually agree upon appropriate amendments to this Agreement consistent with this Section 15.5(a), then either Party shall have the right to terminate this Agreement upon written notice to the other Party. Notwithstanding anything in this Agreement to the contrary, if Gridforce determines in good faith that Gridforce must, immediately or any time after providing notification to Customer pursuant to this Section 15.5(a), terminate this Agreement to avoid becoming or being subject to the provisions of PUHCA 2005 as a public utility company, then Gridforce shall have the right to terminate this Agreement upon written notice to Customer, and Gridforce shall not be required to negotiate with Customer as otherwise required under this Section 15.5(a); provided, however, that Gridforce shall, to the maximum extent practicable without becoming subject to the provisions of PUHCA 2005 as public utility company, provide Customer with as much advance prior written notice of termination as possible and use all commercially reasonable efforts to avoid terminating this Agreement pursuant to this Section 15.5(a).

(b) The Parties also recognize that every transmission facility connected to the North American transmission system must be part of and associated with a Transmission Operator in order to ensure the secure and reliable operation of the North American transmission system and that, in the event Gridforce were to determine that termination of this Agreement is required under this Section 15.5, the Customer would need to transition to another Transmisssion Operator. Accordingly, in the event that Gridforce terminates this Agreement pursuant to this Section 15.5 the Parties shall work to effectuate the transition of the Customer to another Services provider as expeditiously as possible and Gridforce shall, until such time as the Customer is transitioned to another Services provider use commercially reasonable efforts to provide Services to Customer at the Monthly Services Fee or such other compensation as mutually agreed upon by the Parties.

Section 15.6. Headings. The headings used for the sections and articles herein are for convenience and reference purposes only and shall in no way affect the meaning or interpretation of the provisions of this Agreement.

Section 15.7. No Third Party Beneficiaries. Nothing in this Agreement, express or implied, is intended to confer on any Person, other than the Parties to this Agreement, any right or remedy of any nature whatsoever.

Section 15.8. Relationship of the Parties. The Parties are independent contractors, and shall not be deemed to be partners, joint venturers or agents of each other for any purpose, including for purposes of any taxes or for workers' compensation or liability purposes. Nothing contained in this Agreement shall be construed to create a partnership, joint venture, agency or other relationship that may invoke fiduciary obligations between the Parties.

Section 15.9. Accommodation of Financing Parties. To facilitate the procurement or maintenance of financing or refinancing by Customer or any purchaser of the output from a Customer Facility, Gridforce shall cooperate with Customer in good faith, at Customer's expense, in such financing or refinancing efforts and shall agree to reasonable modifications of this Agreement as may be requested to protect the interest of any Persons providing such financing; provided that such modifications do not materially adversely affect Gridforce's rights or duties under this Agreement.

Section 15.10. Counterparts. This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument.

Section 15.11. Telephone Recordings. Except to the extent otherwise expressly provided in this Agreement, the Parties intend that telephonic communications between the Parties may be employed as a matter of normal course in the administration of this Agreement. Each Party agrees that it will not contest or assert any defense (except a defense that the tapes or other recording device are not authentic or have been actively tampered with) to the validity or enforceability of such telephonic communications under laws relating to whether certain agreements are to be in writing or signed by the Party to be thereby bound or the authority of any employee of such Party to make such communication. Each Party consents to the recording of its representatives' telephone conversations without any further notice. Nothing contained in this Section 15.12 shall be construed as in anyway limiting a Party's ability to challenge the admissibility, authenticity or veracity of a telephone communication.

Section 15.12. Construction. This Agreement and any documents or instruments delivered pursuant hereto shall be construed without regard to the identity of the Party who drafted the various provisions of the same. Each and every provision of this Agreement and such other documents and instruments shall be construed as though the Parties participated equally in the drafting of the same. Consequently, the Parties acknowledge and agree that any rule of construction that a document is to be construed against the drafting Party shall not be applicable either to this Agreement or such other documents and instruments.

Section 15.13. Exhibits. The exhibits attached to this Agreement form an integral part of this Agreement, and any and all exhibits referred to in this Agreement are, by such reference, incorporated herein and made a part hereof for all purposes.

Section 15.14. No Publicity. Neither Party shall refer to the other party directly or indirectly in any media release, public announcement, or public disclosure relating to this Agreement or its subject matter, in any promotional or marketing materials, lists, or business presentations, without prior written consent from the other Party for each such use.

IN WITNESS WHEREOF, each Party has caused this Agreement to be executed on its behalf by its duly authorized representative, effective as of the Effective Date. This Agreement shall not become effective as to either Party unless and until executed by both Parties.

Gridforce Energy Management, LLC

By: ______________________________

Its: ______________________________

City of Henderson

By: ______________________________

Its: ______________________________

EXHIBIT A

This Exhibit expressly identifies the requirements of applicable Reliability Standards for which Gridforece and Customer is either solely or jointly responsible. Where Gridforce and Customer are jointly responsible for a requirement, each party will be solely responsible for ensuring compliance as it relates to that party's assets and personnel. Gridforce shall be responsible for implementing new or modified Reliability Standards and coordinating with Customer any new Customer obligations.

Part 1 – Applicable NERC Standards for BA and TOP Registered Entities

Part 2 – Specific NERC Standards to Which Gridforce will Partner with HMP&L

BAL-001-2	R1.	The Responsible Entity shall operate such that the Control Performance Standard 1 (CPS1), calculated in accordance with Attachment 1, is greater than or equal to 100 percent for the applicable Interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
BAL-001-2	R2.	Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
BAL-002-2(i)	R1.	The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:	HIGH	Full Responsibility See CFR00001	None	None	BA		
BAL-002-2(i)	R2.	Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.	HIGH	Full Responsibility See CFR00001	None	None	BA		
BAL-002-2(i)	R3.	Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
BAL-003-1.1	R1.	Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation	HIGH	Full Responsibility See CFR00001	None	None	BA		
BAL-003-1.1	R2.	Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
BAL-003-1.1	R3.	Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
BAL-003-1.1	R4.	Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
BAL-005-1	R1.	The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE.	MEDIUM	Not included in the CFR00001 currently Goes into effect January 1, 2019	None	None	BA		
BAL-005-1	R2.	A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE.	MEDIUM	Not included in the CFR00001 currently Goes into effect January 1, 2019	None	None	BA		
BAL-005-1	R3.	Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: 3.1. that is available a minimum of 99.95% for each calendar year; and, 3.2. with a minimum accuracy of 0.001 Hz.	MEDIUM	Not included in the CFR00001 currently Goes into effect January 1, 2019	None	None	BA		

BAL-005-1	R4.	The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data.	MEDIUM	Not included in the CFR00001 currently Goes into effect January 1, 2019	None	None	BA		
BAL-005-1	R5.	Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year.	MEDIUM	Not included in the CFR00001 currently Goes into effect January 1, 2019	None	None	BA		
BAL-005-1	R6.	Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of Reporting ACE for each Balancing Authority Area.	MEDIUM	Not included in the CFR00001 currently Goes into effect January 1, 2019	None	None	BA		
BAL-005-1	R7.	Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with: *7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,* *7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.*	MEDIUM	Not included in the CFR00001 currently Goes into effect January 1, 2019	Normal (if applicable)	Normal (if applicable)	BA		
BAL-006-2	R1.	Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.	LOWER	Full Responsibility See CFR00001	None	None	BA		
BAL-006-2	R2.	Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.	LOWER	Full Responsibility See CFR00001	None	None	BA		
BAL-006-2	R3.	Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.	LOWER	None	Normal	Normal	BA		
BAL-006-2	R4.	Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:	LOWER	Full Responsibility See CFR00001	None	None	BA		
BAL-006-2	R4.1.	Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:	LOWER	Partial See CFR00001	Not Applicable	Not Applicable	BA		
BAL-006-2	R4.1.1.	The hourly values of Net Interchange Schedule.	LOWER	Full Responsibility See CFR00001	None	None	BA		
BAL-006-2	R4.1.2.	The hourly integrated megawatt-hour values of Net Actual Interchange.	LOWER	None	Not Applicable	Not Applicable	BA		
BAL-006-2	R4.2.	Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.	LOWER	Full Responsibility See CFR00001	None	None	BA		
BAL-006-2	R4.3.	A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).	LOWER	Partial See CFR00001	Not Applicable	Not Applicable	BA		
BAL-006-2	R5.	Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.	LOWER	Full Responsibility See CFR00001	None	None	BA		

CIP-002-5.1a	R1.	R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [Violation Risk Factor: High][Time Horizon: Operations Planning] i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above. 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset; 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).	HIGH	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-002-5.1a	R2.	R2. The Responsible Entity shall: 2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and 2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-003-6	R1.	Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: 1.1 For its high impact and medium impact BES Cyber Systems, if any: 1.1.1. Personnel and training (CIP-004); 1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access; 1.1.3. Physical security of BES Cyber Systems (CIP-006); 1.1.4. System security management (CIP-007); 1.1.5. Incident reporting and response planning (CIP-008); 1.1.6. Recovery plans for BES Cyber Systems (CIP-009); 1.1.7. Configuration change management and vulnerability assessments (CIP-010); 1.1.8. Information protection (CIP-011); and 1.1.9. Declaring and responding to CIP Exceptional Circumstances. 1.2 For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any: 1.2.1. Cyber security awareness; 1.2.2. Physical security controls; 1.2.3. Electronic access controls for Low Impact External Routable Connectivity (LERC) and Dial-up Connectivity; and 1.2.4. Cyber Security Incident response	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-003-6	R2.	Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. Note: An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-003-6	R3.	Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change.	MEDIUM	Normal See CFR00001	Normal	Normal	BA	TO	TOP
CIP-003-6	R4.	The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator.	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP

CIP-003-7	R1.	Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: 1.1. For its high impact and medium impact BES Cyber Systems, if any: 1.1.1. Personnel and training (CIP-004); 1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access; 1.1.3. Physical security of BES Cyber Systems (CIP-006); 1.1.4. System security management (CIP-007); 1.1.5. Incident reporting and response planning (CIP-008); 1.1.6. Recovery plans for BES Cyber Systems (CIP-009); 1.1.7. Configuration change management and vulnerability assessments (CIP-010); 1.1.8. Information protection (CIP-011); and 1.1.9. Declaring and responding to CIP Exceptional Circumstances. 1.2. For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any: 1.2.1. Cyber security awareness; 1.2.2. Physical security controls; 1.2.3. Electronic access controls; 1.2.4. Cyber Security Incident response; 1.2.5. Transient Cyber Assets and Removable Media malicious code risk mitigation; and 1.2.6. Declaring and responding to CIP Exceptional Circumstances.	MEDIUM	Not in CFR00001 Effective Date 1/1/20 Normal	Normal	Normal	BA	TO	TOP
CIP-003-7	R2.	Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. Note: An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.	LOWER	Not in CFR00001 Effective Date 1/1/20 Normal	Normal	Normal	BA	TO	TOP
CIP-003-7	R3.	Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change.	MEDIUM	Not in CFR00001 Effective Date 1/1/20 Normal	Normal	Normal	BA	TO	TOP
CIP-003-7	R4.	The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator.	LOWER	Not in CFR00001 Effective Date 1/1/20 Normal	Normal	Normal	BA	TO	TOP
CIP-004-6	R1.	Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-6 Table R1 – Security Awareness Program.* (please see standard for sub-req's)	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-004-6	R2.	Each Responsible Entity shall implement one or more cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-6 Table R2 – Cyber Security Training Program*. (please see standard for sub-req's)	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-004-6	R3.	Each Responsible Entity shall implement one or more documented personnel risk assessment program(s) to attain and retain authorized electronic or authorized unescorted physical access to BES Cyber Systems that collectively include each of the applicable requirement parts in *CIP-004-6 Table R3 – Personnel Risk Assessment Program*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-004-6	R4.	Each Responsible Entity shall implement one or more documented access management program(s) that collectively include each of the applicable requirement parts in *CIP-004-6 Table R4 – Access Management Program.* (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP

CIP-004-6	R5.	Each Responsible Entity shall implement one or more documented access revocation program(s) that collectively include each of the applicable requirement parts in *CIP-004-6 Table R5 – Access Revocation*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-005-5	R1.	Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-5 Table R1 – Electronic Security Perimeter*.	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-005-5	R2.	Each Responsible Entity allowing Interactive Remote Access to BES Cyber Systems shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-5 Table R2 – Interactive Remote Access Management*.	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-006-6	R1.	Each Responsible Entity shall implement one or more documented physical security plan(s) that collectively include all of the applicable requirement parts in *CIP-006-6 Table R1 – Physical Security Plan*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-006-6	R2.	Each Responsible Entity shall implement one or more documented visitor control program(s) that include each of the applicable requirement parts in *CIP-006-6 Table R2 – Visitor Control Program.* (please see standard for sub-req's)	MEDIUM	Normal See CFR00001	Normal	Normal	BA	TO	TOP
CIP-006-6	R3.	Each Responsible Entity shall implement one or more documented Physical Access Control System maintenance and testing program(s) that collectively include each of the applicable requirement parts in *CIP-006-6 Table R3 – Maintenance and Testing Program*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-007-6	R1.	Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R1 – Ports and Services*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-007-6	R2.	Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R2 – Security Patch Management*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-007-6	R3.	Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R3 – Malicious Code Prevention*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-007-6	R4.	Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R4 – Security Event Monitoring*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-007-6	R5.	Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R5 – System Access Controls*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP

CIP-008-5	R1.	Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5 Table R1 – Cyber Security Incident Response Plan Specifications*.	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-008-5	R2.	Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in *CIP-008-5 Table R2 – Cyber Security Incident Response Plan Implementation and Testing.*	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-008-5	R3.	Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in *CIP-008-5 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*.	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-009-6	R1.	Each Responsible Entity shall have one or more documented recovery plan(s) that collectively include each of the applicable requirement parts in *CIP-009-6 Table R1 – Recovery Plan Specifications*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-009-6	R2.	Each Responsible Entity shall implement its documented recovery plan(s) to collectively include each of the applicable requirement parts in *CIP-009-6 Table R2 – Recovery Plan Implementation and Testing. (please see standard for sub-req's)*	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-009-6	R3.	Each Responsible Entity shall maintain each of its recovery plan(s) in accordance with each of the applicable requirement parts in *CIP-009-6 Table R3 – Recovery Plan Review, Update and Communication*. (please see standard for sub-req's)	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-010-2	R1.	Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-010-2 Table R1 – Configuration Change Management*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-010-2	R2.	Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-010-2 Table R2 – Configuration Monitoring.* (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-010-2	R3.	Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-010-2 Table R3– Vulnerability Assessments*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-010-2	R4.	Each Responsible Entity, for its high impact and medium impact BES Cyber Systems and associated Protected Cyber Assets, shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) for Transient Cyber Assets and Removable Media that include the sections in Attachment 1.	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP

CIP-011-2	R1.	Each Responsible Entity shall implement one or more documented information protection program(s) that collectively includes each of the applicable requirement parts in *CIP-011-2 Table R1 – Information Protection*. (please see standard for sub-req's)	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-011-2	R2.	Each Responsible Entity shall implement one or more documented process(es) that collectively include the applicable requirement parts in *CIP-011-2 Table R2 – BES Cyber Asset Reuse and Disposal*. (please see standard for sub-req's)	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
CIP-014-2	R1.	Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.	HIGH	None	None	Normal		TO	
CIP-014-2	1.1.	Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.	HIGH	None	None	Normal		TO	
CIP-014-2	1.2.	The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.	HIGH	None	None	Normal		TO	
CIP-014-2	R2.	Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1.	MEDIUM	None	None	Normal		TO	
CIP-014-2	2.1.	Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience.	MEDIUM	None	None	Normal		TO	
CIP-014-2	2.2.	The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.	MEDIUM	None	None	Normal		TO	
CIP-014-2	2.3.	If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.	MEDIUM	None	None	Normal		TO	
CIP-014-2	2.4.	Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.	MEDIUM	None	None	Normal		TO	

CIP-014-2	3.	For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2.	LOWER	None	None	Normal		TO	
CIP-014-2	3.1.	If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.	LOWER	None	None	Normal		TO	
CIP-014-2	4.	Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following:	MEDIUM	None	Not Applicable	Normal		TO	TOP
CIP-014-2	4.1.	Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);	MEDIUM	None	Not Applicable	Normal		TO	TOP
CIP-014-2	4.2.	Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and	MEDIUM	None	Not Applicable	Normal		TO	TOP
CIP-014-2	4.3.	Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.	MEDIUM	None	Not Applicable	Normal		TO	TOP
CIP-014-2	5.	Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes:	HIGH	None	Not Applicable	Normal		TO	TOP
CIP-014-2	5.1.	Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.	HIGH	None	Not Applicable	Normal		TO	TOP
CIP-014-2	5.2.	Law enforcement contact and coordination information.	HIGH	None	Not Applicable	Normal		TO	TOP
CIP-014-2	5.3.	A timeline for executing the physical security enhancements and modifications specified in the physical security plan.	HIGH	None	Not Applicable	Normal		TO	TOP
CIP-014-2	5.4.	Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).	HIGH	None	Not Applicable	Normal		TO	TOP
CIP-014-2	6.	Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5.	MEDIUM	None	Not Applicable	Normal		TO	TOP
CIP-014-2	6.1.	Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: · An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. · An entity or organization approved by the ERO. · A governmental agency with physical security expertise. · An entity or organization with demonstrated law enforcement, government, or military physical security expertise.	MEDIUM	None	Not Applicable	Normal		TO	TOP
CIP-014-2	6.2.	The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.	MEDIUM	None	Not Applicable	Normal		TO	TOP
CIP-014-2	6.3.	If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation: · Modify its evaluation or security plan(s) consistent with the recommendation; or · Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.	MEDIUM	None	Not Applicable	Normal		TO	TOP

CIP-014-2	6.4.	Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.	MEDIUM	None	Not Applicable	Normal		TO	TOP
COM-001-3	R3.	Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply):	HIGH	None	Normal	Normal			TOP
COM-001-3	3.1.	Its Reliability Coordinator.	HIGH	None	Normal	None			TOP
COM-001-3	3.2.	Each Balancing Authority within its Transmission Operator Area.	HIGH	None	Not Applicable	None			TOP
COM-001-3	3.3.	Each Distribution Provider within its Transmission Operator Area.	HIGH	None	Normal	Normal			TOP
COM-001-3	3.4.	Each Generator Operator within its Transmission Operator Area.	HIGH	None	Normal	None			TOP
COM-001-3	3.5.	Each adjacent Transmission Operator synchronously connected.	HIGH	None	Normal	None			TOP
COM-001-3	3.6.	Each adjacent Transmission Operator asynchronously connected.	HIGH	None	Not Applicable	None			TOP
COM-001-3	R4.	Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities:	HIGH	None	Normal	None			TOP
COM-001-3	4.1.	Its Reliability Coordinator.	HIGH	None	Normal	None			TOP
COM-001-3	4.2.	Each Balancing Authority within its Transmission Operator Area.	HIGH	None	Not Applicable	None			TOP
COM-001-3	4.3.	Each adjacent Transmission Operator synchronously connected.	HIGH	None	Normal	None			TOP
COM-001-3	4.4.	Each adjacent Transmission Operator asynchronously connected.	HIGH	None	Not Applicable	None			TOP
COM-001-3	R5.	Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply):	HIGH	Partial See CFR00001	Partial	Partial	BA		
COM-001-3	5.1.	Its Reliability Coordinator.	HIGH	Full Responsibility See CFR00001	None	None	BA		
COM-001-3	5.2.	Each Transmission Operator that operates Facilities within its Balancing Authority Area.	HIGH	Full Responsibility See CFR00001	None	None	BA		
COM-001-3	5.3.	Each Distribution Provider within its Balancing Authority Area.	HIGH	None	Normal	Normal	BA		
COM-001-3	5.4.	Each Generator Operator that operates Facilities within its Balancing Authority Area.	HIGH	None	Normal	None	BA		
COM-001-3	5.5.	Each Adjacent Balancing Authority.	HIGH	Full Responsibility See CFR00001	None	None	BA		
COM-001-3	R6.	Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities:	HIGH	Full Responsibility See CFR00001	None	None	BA		
COM-001-3	6.1.	Its Reliability Coordinator.	HIGH	Full Responsibility See CFR00001	None	None	BA		
COM-001-3	6.2.	Each Transmission Operator that operates Facilities within its Balancing Authority Area.	HIGH	Full Responsibility See CFR00001	None	None	BA		
COM-001-3	6.3.	Each Adjacent Balancing Authority.	HIGH	Full Responsibility See CFR00001	None	None	BA		
COM-001-3	R9.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours.	MEDIUM	Full Responsibility See CFR00001 None See CFR00132	None (BA) Normal (TOP)	None	BA		TOP
COM-001-3	R10.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer.	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	None	BA		TOP
COM-001-3	R12.	Each Reliability Coordinator, Transmission Operator, Generator Operator, and Balancing Authority shall have internal Interpersonal Communication capabilities for the exchange of information necessary for the Reliable Operation of the BES. This includes communication capabilities between Control Centers within the same functional entity, and/or between a Control Center and field personnel.	HIGH	Normal See CFR00001 None See CFR00132	Normal	None	BA		TOP

COM-002-4	R1.	Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: [Please see the standard for more information]	LOWER	Normal See CFR00001 None See CFR00132	Normal	None	BA		TOP
COM-002-4	R2.	Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction.	LOWER	Normal See CFR00001 None	Normal	Normal	BA		TOP
COM-002-4	R4.	Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: [Please see the standard for more information]	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	None	BA		TOP
COM-002-4	R5.	Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: • Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6). • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.	HIGH	Normal See CFR00001 None See CFR00132	Normal	None	BA		TOP
COM-002-4	R6.	Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	HIGH	Normal See CFR00001 None See CFR00132	Normal	None	BA		TOP
COM-002-4	R7.	Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction.	HIGH	Normal See CFR00001 None See CFR00132	Normal	None	BA		TOP
EOP-004-3	R1.	Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2-3 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority).	LOWER	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
EOP-004-3	R2.	Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time).	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
EOP-004-3	R3.	Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year.	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP

EOP-004-4	R1.	Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority).	LOWER	Not included in the CFR00001 currently None See CFR00132 Goes into effect April 1, 2019	Normal	Normal	BA	TO	TOP
EOP-004-4	R2.	Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).	MEDIUM	Not included in the CFR00001 currently None See CFR00132 Goes into effect April 1, 2019	Normal	Normal	BA	TO	TOP
EOP-005-3	R1.	Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: 1.1. Strategies for System restoration that are coordinated with its Reliability Coordinator's high level strategy for restoring the Interconnection. 1.2. A description of how all Agreements or mutually-agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration. 1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of its Reliability Coordinator. 1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit. 1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started. 1.6. Identification of acceptable operating voltage and frequency limits during restoration. 1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection. 1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control. 1.9. Operating Processes for transferring operations back to the Balancing Authority in accordance with its Reliability Coordinator's criteria.	HIGH	None See CFR00132	Normal	Normal			TOP
EOP-005-3	R2.	Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	MEDIUM	None See CFR00132	Normal	Normal			TOP
EOP-005-3	R3.	Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule.	MEDIUM	None See CFR00132	Normal	Normal			TOP
EOP-005-3	R4.	Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: 4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications. 4.2. Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.	MEDIUM	None See CFR00132	Normal	Normal			TOP
EOP-005-3	R5.	Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date.	LOWER	None See CFR00132	Normal	None			TOP
EOP-005-3	R6.	Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: 6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads. 6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits. 6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.	MEDIUM	None See CFR00132	Normal	Normal			TOP

EOP-005-3	R7.	Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: 7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years. 7.2. A list of required tests including: 7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System. 7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits. 7.3. The minimum duration of each of the required tests.	MEDIUM	None See CFR00132	None	Normal			TOP
EOP-005-3	R8.	R8. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall include training on the following: 8.1. System restoration plan including coordination with its Reliability Coordinator and Generator Operators included in the restoration plan. 8.2. Restoration priorities. 8.3. Building of cranking paths. 8.4. Synchronizing (re-energized sections of the System). 8.5. Transition of Demand and resource balance within its area to the Balancing Authority.	MEDIUM	None See CFR00132	Normal	None			TOP
EOP-005-3	R9.	Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks.	MEDIUM	None See CFR00132	Normal	Normal		TO	TOP
EOP-005-3	R10.	Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator.	MEDIUM	None See CFR00132	Normal	Normal			TOP
EOP-005-3	R11.	Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements.	MEDIUM	None See CFR00132	None	Normal			TOP
EOP-008-2	R1.	R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] 1.1. The location and method of implementation for providing backup functionality. 1.2. A summary description of the elements required to support the backup functionality. These elements shall include: 1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES. 1.2.2. Data exchange capabilities. 1.2.3. Interpersonal Communications. 1.2.4. Power source(s). 1.2.5. Physical and cyber security. 1.3. An Operating Process for keeping the backup functionality consistent with the primary control center. 1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. 1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours. 1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include: 1.6.1. A list of all entities to notify when there is a change in operating locations. 1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality. 1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.	MEDIUM	Not included in the CFR00001 currently Goes into effect April 1, 2019 None See CFR00132	Normal	None	BA		TOP
EOP-008-2	R2.	Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality.	LOWER	Not included in the CFR00001 currently Goes into effect April 1, 2019 None See CFR00132	Normal	None	BA		TOP

EOP-008-2	R4.	R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: • Planned outages of the primary or backup functionality of two weeks or less • Unplanned outages of the primary or backup functionality	HIGH	Not included in the CFR00001 currently Goes into effect April 1, 2019 None See CFR00132	Normal	None	BA		TOP
EOP-008-2	R5.	R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. 5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.	MEDIUM	Not included in the CFR00001 currently Goes into effect April 1, 2019 None See CFR00132	Normal	None	BA		TOP
EOP-008-2	R6.	Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards.	MEDIUM	Not included in the CFR00001 currently Goes into effect April 1, 2019 None See CFR00132	Normal	None	BA		TOP
EOP-008-2	R7.	R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: 7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality. 7.2. The backup functionality for a minimum of two continuous hours.	MEDIUM	Not included in the CFR00001 currently Goes into effect April 1, 2019 None See CFR00132	Normal	None	BA		TOP
EOP-008-2	R8.	R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality.	MEDIUM	Not included in the CFR00001 currently Goes into effect April 1, 2019 None See CFR00132	Normal	None	BA		TOP
EOP-010-1	R3.	Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: 3.1. Steps or tasks to receive space weather information. 3.2. System Operator actions to be initiated based on predetermined conditions. 3.3. The conditions for terminating the Operating Procedure or Operating Process.	MEDIUM	None See CFR00132	Normal	Normal			TOP
EOP-011-1	R1.	Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable:	HIGH	None See CFR00132	Normal	Normal			TOP
EOP-011-1	R1.1.	Roles and responsibilities for activating the Operating Plan(s)	HIGH	None See CFR00132	Normal	Normal			TOP
EOP-011-1	R1.2.	Processes to prepare for and mitigate Emergencies including:	HIGH	None See CFR00132	Normal	Normal			TOP
EOP-011-1	R1.2.1.	Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;	HIGH	None See CFR00132	Normal	None			TOP
EOP-011-1	R1.2.2.	Cancellation or recall of Transmission and generation outages;	HIGH	None See CFR00132	Normal	Normal			TOP
EOP-011-1	R1.2.3.	Transmission system reconfiguration;	HIGH	None See CFR00132	Normal	Normal			TOP

FERC Approved Standards

Part 1 – Applicable NERC Standards for BA and TOP Registered Entities

EOP-011-1	R1.2.4.	Redispatch of generation request;	HIGH	None See CFR00132	Normal	Normal			TOP
EOP-011-1	R1.2.5.	Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	HIGH	None See CFR00132	Normal	Normal			TOP
EOP-011-1	R1.2.6.	Reliability impacts of extreme weather conditions.	HIGH	None See CFR00132	Normal	Normal			TOP
EOP-011-1	R2.	Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable:	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.1.	Roles and responsibilities for activating the Operating Plan(s);	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.	Processes to prepare for and mitigate Emergencies including:	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.1.	Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;	HIGH	Normal See CFR00001	Normal	None	BA		
EOP-011-1	R2.2.2.	Requesting an Energy Emergency Alert, per Attachment 1;	HIGH	Normal See CFR00001	Normal	None	BA		
EOP-011-1	R2.2.3.	Managing generating resources in its Balancing Authority Area to address:	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.3.1.	capability and availability;	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.3.2.	fuel supply and inventory concerns;	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.3.3.	fuel switching capabilities; and	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.3.4.	environmental constraints.	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.4.	Public appeals for voluntary Load reductions;	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.5.	Requests to government agencies to implement their programs to achieve necessary energy reductions;	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.6.	Reduction of internal utility energy use;	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.7.	Use of Interruptible Load, curtailable Load and demand response;	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.8.	Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R2.2.9.	Reliability impacts of extreme weather conditions.	HIGH	Normal See CFR00001	Normal	Normal	BA		
EOP-011-1	R4.	Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator.	HIGH	Normal See CFR00001 None See CFR00132	Normal	Normal	BA		TOP
FAC-001-2	R1.	Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *(please see standard for sub-req's)*	LOWER	None	None	Normal		TO	
FAC-001-2	R3.	Each Transmission Owner shall address the following items in its Facility interconnection requirements: *(please see standard for sub-req's)*	LOWER	None	None	Normal		TO	
FAC-001-3	R1.	Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for	LOWER	None	None	Normal		TO	
FAC-001-3	1.1.	generation Facilities;	LOWER	None	None	Normal		TO	
FAC-001-3	1.2.	transmission Facilities; and	LOWER	None	None	Normal		TO	
FAC-00[illegible] 02/2018	1.3.	end-user Facilities. 14	LOWER	None	None	Normal		TO	

FAC-001-3	R3.	Each Transmission Owner shall address the following items in its Facility interconnection requirements:	LOWER	None	None	Normal		TO	
FAC-001-3	3.1.	Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).	LOWER	None	None	Normal		TO	
FAC-001-3	3.2.	Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.	LOWER	None	None	Normal		TO	
FAC-001-3	3.3.	Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.	LOWER	None	None	Normal		TO	
FAC-002-2	R3.	Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4	MEDIUM	None	None	Normal		TO	
FAC-002-2	R4.	Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4.	MEDIUM	None	None	Normal		TO	
FAC-003-4	R1.	Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below	HIGH	None	None	Normal		TO	
FAC-003-4	1.1.	An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,	HIGH	None	None	Normal		TO	
FAC-003-4	1.2.	An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,	HIGH	None	None	Normal		TO	
FAC-003-4	1.3.	An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage	HIGH	None	None	Normal		TO	
FAC-003-4	1.4.	An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.	HIGH	None	None	Normal		TO	
FAC-003-4	R2.	Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below	HIGH	None	None	Normal		TO	
FAC-003-4	2.1.	An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,		None	None	Normal		TO	
FAC-003-4	2.2.	An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,		None	None	Normal		TO	
FAC-003-4	2.3.	An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,		None	None	Normal		TO	
FAC-003-4	2.4.	An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.		None	None	Normal		TO	
FAC-003-4	R3.	Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:	LOWER	None	None	Normal		TO	
FAC-003-4	3.1.	Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;	LOWER	None	None	Normal		TO	
FAC-003-4	3.2.	Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.	LOWER	None	None	Normal		TO	
FAC-003-4	R4.	Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment	MEDIUM	None	None	Normal		TO	
FAC-003-4	R5.	When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments	MEDIUM	None	None	Normal		TO	
FAC-003-4	R6.	Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW	MEDIUM	None	None	Normal		TO	
FAC-003-4	R7.	Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended	MEDIUM	None	None	Normal		TO	
FAC-003-4	7.1.	Change in expected growth rate/environmental factors	MEDIUM	None	None	Normal		TO	
FAC-003-4	7.2.	Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner	MEDIUM	None	None	Normal		TO	
FAC-003-4	7.3.	Rescheduling work between growing seasons	MEDIUM	None	None	Normal		TO	
FAC-003-4	7.4.	Crew or contractor availability/Mutual assistance agreements	MEDIUM	None	None	Normal		TO	
FAC-003-4	7.5.	Identified unanticipated high priority work	MEDIUM	None	None	Normal		TO	

FAC-003-4	7.6.	Weather conditions/Accessibility	MEDIUM	None	None	Normal		TO	
FAC-003-4	7.7.	Permitting delays	MEDIUM	None	None	Normal		TO	
FAC-003-4	7.8.	Land ownership changes/Change in land use by the landowner	MEDIUM	None	None	Normal		TO	
FAC-003-4	7.9.	Emerging technologies	MEDIUM	None	None	Normal		TO	
FAC-008-3	R3.	Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: [See standard for methodology requirements]	MEDIUM	None	None	Normal		TO	
FAC-008-3	R4.	Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request. (Retirement approved by FERC effective January 21, 2014)	LOWER	None	None	None		TO	
FAC-008-3	R5.	If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why. (Retirement approved by FERC effective January 21, 2014)	LOWER	None	None	None		TO	
FAC-008-3	R6.	Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.	MEDIUM	None	None	Normal		TO	
FAC-008-3	R8.	Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): [*See standard for requirements of providing requested information*]	MEDIUM	None	None	Normal		TO	
FAC-014-2	R2.	The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.	MEDIUM	None	None	Normal			TOP
FAC-014-2	R5.2.	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	MEDIUM	None	Normal	Normal			TOP
INT-004-3.1	R3.	Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.	LOWER	Full Responsibility See CFR00001	None	None	BA		
INT-006-4	R1.	Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Please see the standard for more information]	LOWER	Full Responsibility See CFR00001	None	None	BA		
INT-006-4	R2.	Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Please see the standard for more information]	LOWER	Full Responsibility See CFR00001	None	None			
INT-006-4	R3.	The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. [Please see the standard for more information]	LOWER	Full Responsibility See CFR00001	None	None	BA		
INT-006-4	R4.	Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: [Please see the standard for more information]	LOWER	Full Responsibility See CFR00001	None	None	BA		
INT-006-4	R5.	For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Please see the standard for more information]	LOWER	Full Responsibility See CFR00001	None	None	BA		
INT-009-2.1	R1.	R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		

INT-009-2.1	R2.	The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).	MEDIUM	Partial See CFR00001	Normal (if applicable)	Normal (if applicable)	BA		
INT-009-2.1	R3.	Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
INT-010-2.1	R1.	The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required.	LOWER	Full Responsibility See CFR00001	None	None	BA		
INT-010-2.1	R2.	Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons.	LOWER	Full Responsibility See CFR00001	None	None	BA		
INT-010-2.1	R3.	Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons.	LOWER	Full Responsibility See CFR00001	None	None	BA		
IRO-001-4	R2.	Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	HIGH	Normal See CFR00001 None See CFR00132	Normal	Normal	BA		TOP
IRO-001-4	R3.	Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1.	HIGH	Normal See CFR00001 None See CFR00132	Normal	Normal	BA		TOP
IRO-006-5	R1.	Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request.	HIGH	Full Responsibility See CFR00001	None	None	BA		
IRO-010-2	R3.	Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:	LOWER	Full Responsibility See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
IRO-010-2	3.1.	A mutually agreeable format.	LOWER	Full Responsibility See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
IRO-010-2	3.2.	A mutually agreeable process for resolving data conflicts.	LOWER	Full Responsibility See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
IRO-010-2	3.3.	A mutually agreeable security protocol.	LOWER	Full Responsibility See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP

IRO-017-1	R2.	Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.	MEDIUM	Full Responsibility See CFR00001 None See CFR00132	Normal	Normal	BA		TOP
MOD-001-1a	R1.	Each Transmission Operator shall select one of the methodologies listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [Time Horizon: Operations Planning] □ The Area Interchange Methodology, as described in MOD-028 □ The Rated System Path Methodology, as described in MOD-029 □ The Flowgate Methodology, as described in MOD-030	MEDIUM	Full Responsibility See CFR00132	None	None			TOP
MOD-001-1a	R6.	When calculating Total Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. [Time Horizon: Operations Planning]	MEDIUM	Full Responsibility See CFR00132	None	None			TOP
MOD-004-1	R10.	The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [Time Horizon: Same-day Operations]	LOWER	Full Responsibility See CFR00001	None	None	BA		
MOD-004-1	R11.	When reviewing an Arranged Interchange using CBM, all Balancing Authorities and Transmission Service Providers shall waive, within the bounds of reliable operation, any Real-time timing and ramping requirements.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-008-1	R1.	Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID) that includes, as a minimum, the following information: [Time Horizon: Operations Planning]	MEDIUM	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R1.1.	Identification of (on each of its respective ATC Paths or Flowgates) each of the following components of uncertainty if used in establishing TRM, and a description of how that component is used to establish a TRM value: - Aggregate Load forecast. - Load distribution uncertainty. - Forecast uncertainty in Transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages). - Allowances for parallel path (loop flow) impacts. - Allowances for simultaneous path interactions. - Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation). - Short-term System Operator response (Operating Reserve actions). - Reserve sharing requirements. - Inertial response and frequency bias.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R1.2.	The description of the method used to allocate TRM across ATC Paths or Flowgates.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R1.3.	The identification of the TRM calculation used for the following time periods:	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R1.3.1.	Same day and real-time.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R1.3.2.	Day-ahead and pre-schedule.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R1.3.3.	Beyond day-ahead and pre-schedule, up to thirteen months ahead.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R2.	Each Transmission Operator shall only use the components of uncertainty from R1.1 to establish TRM, and shall not include any of the components of Capacity Benefit Margin (CBM). Transmission capacity set aside for reserve sharing agreements can be included in TRM. [Time Horizon: Operations Planning]	MEDIUM	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R3.	Each Transmission Operator shall make available its TRMID, and if requested, underlying documentation (if any) used to determine TRM, in the format used by the Transmission Operator, to any of the following who make a written request no more than 30 calendar days after receiving the request. [Time Horizon: Operations Planning] • Transmission Service Providers • Reliability Coordinators • Planning Coordinators • Transmission Planner • Transmission Operators	LOWER	Full Responsibility See CFR00132	None	None			TOP

MOD-008-1	R4.	Each Transmission Operator that maintains TRM shall establish TRM values in accordance with the TRMID at least once every 13 months. [Time Horizon: Operations Planning]	MEDIUM	Full Responsibility See CFR00132	None	None			TOP
MOD-008-1	R5.	The Transmission Operator that maintains TRM shall provide the TRM values to its Transmission Service Provider(s) and Transmission Planner(s) no more than seven calendar days after a TRM value is initially established or subsequently changed. [Time Horizon: Operations Planning]	MEDIUM	Full Responsibility See CFR00132	None	None			TOP
MOD-025-2	R3.	Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: 3.1. Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous condenser units. 3.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.	MEDIUM	None	None	Normal		TO	
MOD-028-2	R2.	When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following:	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R2.1.	Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R2.2.	Modeling data and topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R2.3.	Facility Ratings specified by the Generator Owners and Transmission Owners.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R3.	When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed:	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R3.1.	For TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R3.1.1.	Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R3.1.2.	A daily or hourly load forecast for TTCs used in current-day and next-day ATC calculations.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R3.1.3.	A daily load forecast for TTCs used in ATC calculations for days two through 31.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R3.1.4.	A monthly load forecast for TTCs used in ATC calculations for months two through 13 months TTCs.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R3.1.5.	Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R4.	When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions:	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R4.1.	Use all Contingencies meeting the criteria described in the ATCID.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R4.2.	Respect any contractual allocations of TTC.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP

MOD-028-2	R4.3.	Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows: - If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source. - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source. - If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source. - If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source. - If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point shall as the sink. - If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate representation" in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink. - If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an "equivalence," or an "aggregate representation" in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink. - If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R5.	Each Transmission Operator shall establish TTC for each ATC Path as defined below:	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R5.1.	At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R5.2.	At least once per calendar month for TTCs used in monthly ATC calculations.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R5.3.	Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R6.	Each Transmission Operator shall establish TTC for each ATC Path using the following process:	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R6.1.	Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: - A System Operating Limit is reached on the Transmission Service Provider's system, or - A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater .	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R6.2.	If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R6.3.	Use (as the TTC) the lesser of: - The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or - The sum of Facility Ratings of all ties comprising the ATC Path.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R6.4.	For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R7.	The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R7.1.	One calendar day after its determination for TTCs used in hourly and daily ATC calculations.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-028-2	R7.2.	Seven calendar days after its determination for TTCs used in monthly ATC calculations.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP

MOD-029-2a	R1.	When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements:	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.	The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.1.	Includes at least:	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.1.1.	The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.1.2.	All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.1.3.	Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.2.	Models all system Elements as in-service for the assumed initial conditions.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.3.	Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.4.	Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.5.	Uses Load forecast by Balancing Authority.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.6.	Uses Transmission Facility additions and retirements.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.7.	Uses Generation Facility additions and retirements.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.8.	Uses Remedial Action Scheme (RAS) models where currently existing or projected for implementation within the studied time horizon.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.9.	Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.1.10.	Includes any other modeling requirements or criteria specified in the ATCID.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R1.2.	Uses Facility Ratings as provided by the Transmission Owner and Generator Owner	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.	The Transmission Operator shall use the following process to determine TTC:	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.1.	Except where otherwise specified within MOD-029-2a, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.1.1.	When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.1.2.	When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP

MOD-029-2a	R2.1.3.	Uncontrolled separation shall not occur.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.2.	Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a Remedial Action Scheme (RAS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a RAS.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.3.	For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.4.	For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.5.	The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.6.	Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.7.	For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R2.8.	Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.	No Individual VRF Assigned	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R3.	Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-029-2a	R4.	Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.	LOWER	None	Not Applicable	Not Applicable			TOP
MOD-030-3	R2.	The Transmission Operator shall perform the following:	To Be Determined	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.	Include Flowgates used in the AFC process based, at a minimum, on the following criteria:	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.1.	Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.1.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.1.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.1.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.2.	Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.2.1.	Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.2.2.	Only the most limiting element in a series configuration needs to be included as a Flowgate.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.2.3.	If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP

MOD-030-3	R2.1.3.	Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.4.	Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.4.1.	The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and [See standard for additional information.]	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.1.4.2.	The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.2.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.3.	At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.4.	Establish the TFC of each of the defined Flowgates as equal to: [See standard for additional information.]	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.5.	At a minimum, establish the TFC once per calendar year.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.5.1.	If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R2.6.	Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R3.	The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria:	To Be Determined	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R3.1.	Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.	No Individual VRF Assigned	Partial See CFR00132	Normal	Normal			TOP
MOD-030-3	R3.2.	Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R3.3.	Updated at least once per month for AFC calculations for months two through 13.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-030-3	R3.4.	Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities161kV or below is allowed.	No Individual VRF Assigned	Partial See CFR00132	None	Normal			TOP
MOD-030-3	R3.5.	Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.	No Individual VRF Assigned	Full Responsibility See CFR00132	None	None			TOP
MOD-031-2	R1.	Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include:	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-031-2	1.1.	A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-031-2	1.2.	A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).	MEDIUM	Full Responsibility See CFR00001	None	None	BA		

MOD-031-2	1.3.	1.3. A request to provide any or all of the following actual data, as necessary: 1.3.1. Integrated hourly Demands in megawatts for the prior calendar year. 1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year. 1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year. 1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year. 1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-031-2	1.4.	1.4. A request to provide any or all of the following forecast data, as necessary: 1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years. 1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years. 1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future. 1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future. 1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-031-2	1.5.	1.5. A request to provide any or all of the following summary explanations, as necessary,: 1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts. 1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator. 1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load. 1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted. 1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-031-2	R2.	Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-031-2	R3.	The Planning Coordinator or the Balancing Authority shall provide the data listed under Requirement R1 Parts 1.3 through 1.5 for their area to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties.	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-031-2	R4.	R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or	MEDIUM	Full Responsibility See CFR00001	None	None	BA		
MOD-032-1	R2.	Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.	MEDIUM	Full Responsibility See CFR00001	None	None	BA	TO	

MOD-032-1	R3.	Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: [Please see the standard for more information]	LOWER	Full Responsibility See CFR00001	None	None	BA	TO	
MOD-033-1	R2.	Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation.	LOWER	None See CFR00132	Normal	Normal			TOP
NUC-001-3	R2.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements[1] that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.	MEDIUM	Normal See CFR00001 None See CFR00132	Not Applicable	Not Applicable	BA	TO	TOP
NUC-001-3	R3.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator.:	MEDIUM	Normal See CFR00001 None See CFR00132	Not Applicable	Not Applicable	BA	TO	TOP
NUC-001-3	R4.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: (please see standard for sub-req's)	HIGH	Normal See CFR00001 None See CFR00132	Not Applicable	Not Applicable	BA	TO	TOP
NUC-001-3	R5.	Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall operate the nuclear plant to meet the NPIRs.	HIGH	Normal See CFR00001 None See CFR00132	Not Applicable	Not Applicable			
NUC-001-3	R6.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs.	MEDIUM	Normal See CFR00001 None See CFR00132	Not Applicable	Not Applicable	BA	TO	TOP
NUC-001-3	R7.	Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design (e.g., protective relay setpoints), configuration, operations, limits, or capabilities that may impact the ability of the electric system to meet the NPIRs.	HIGH	Normal See CFR00001 None See CFR00132	Not Applicable	Not Applicable			
NUC-001-3	R8.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design (e.g., protective relay setpoints), configuration, operations, limits, or capabilities that may impact the ability of the electric system to meet the NPIRs.	HIGH	Normal See CFR00001 None See CFR00132	Not Applicable	Not Applicable	BA	TO	TOP

NUC-001-3	R9.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include the following elements in aggregate within the Agreement(s) identified in R2. • Where multiple Agreements with a single Transmission Entity are put into effect, the R9 elements must be addressed in aggregate within the Agreements; however, each Agreement does not have to contain each element. The Nuclear Plant Generator Operator and the Transmission Entity are responsible for ensuring all the R9 elements are addressed in aggregate within the Agreements. • Where Agreements with multiple Transmission Entities are required, the Nuclear Plant Generator Operator is responsible for ensuring all the R9 elements are addressed in aggregate within the Agreements with the Transmission Entities. The Agreements with each Transmission Entity do not have to contain each element; however, the Agreements with the multiple Transmission Entities, in the aggregate, must address all R9 elements. For each Agreement(s), the Nuclear Plant Generator Operator and the Transmission Entity are responsible to ensure the Agreement(s) contain(s) the elements of R9 applicable to that Transmission Entity. *(please see standard for sub-req's)*	MEDIUM	Normal See CFR00001 None See CFR00132	Not Applicable	Not Applicable	BA	TO	TOP
PER-003-1	R2.	Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates: 2.1. Areas of Competency 2.1.1. Transmission operations 2.1.2. Emergency preparedness and operations 2.1.3. System operations 2.1.4. Protection and control 2.1.5. Voltage and reactive 2.2. Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator	HIGH	None See CFR00132	Normal	None			TOP
PER-003-1	R3.	Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates: 3.1. Areas of Competency 3.1.1. Resources and demand balancing 3.1.2. Emergency preparedness and operations 3.1.3. System operations 3.1.4. Interchange scheduling and coordination 3.2. Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator • Balancing and Interchange Operator	HIGH	Normal See CFR00001	Normal	None	BA		
PER-005-2	R1.	Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: [Please see the standard for more information]	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	None	BA		TOP
PER-005-2	R2.	Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: [Please see the standard for more information]	MEDIUM	None	None	Normal		TO	
PER-005-2	R3.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. [Please see the standard for more information]	HIGH	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
PER-005-2	R4.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. [Please see the standard for more information]	MEDIUM	Normal See CFR00001 None See CFR00132	Normal	Normal	BA	TO	TOP
PER-005-2	R5.	Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. [Please see the standard for more information]	MEDIUM	Full Responsibility See CFR00001	None	None	BA		TOP

PRC-001-1.1(ii)	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.	HIGH	Normal See CFR00001 None See CFR00132	Normal	Normal	BA		TOP
PRC-001-1.1(ii)	R2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	HIGH	None See CFR00132	Normal	Normal			TOP
PRC-001-1.1(ii)	R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	HIGH	None See CFR00132	Normal	Normal			TOP
PRC-001-1.1(ii)	R3.	A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	No Individual VRF Assigned	None See CFR00132	None	Normal			TOP
PRC-001-1.1(ii)	R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	HIGH	None See CFR00132	None	Normal			TOP
PRC-001-1.1(ii)	R4.	Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	HIGH	None See CFR00132	None	Normal			TOP
PRC-001-1.1(ii)	R5.	A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:	HIGH	None See CFR00132	None	Normal			TOP
PRC-001-1.1(ii)	R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	HIGH	None See CFR00132	None	Normal			TOP
PRC-001-1.1(ii)	R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	HIGH	None See CFR00132	Normal	Normal	BA		TOP
PRC-002-2	R1.	Each Transmission Owner shall:	LOWER	None	None	Normal		TO	
PRC-002-2	R1.1.	Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.	LOWER	None	None	Normal		TO	
PRC-002-2	R1.2.	Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.	LOWER	None	None	Normal		TO	
PRC-002-2	R1.3.	Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.	LOWER	None	None	Normal		TO	
PRC-002-2	R2.	Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses.	LOWER	None	None	Normal		TO	
PRC-002-2	R3.	Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1:	LOWER	None	None	Normal		TO	
PRC-002-2	R3.1.	Phase-to-neutral voltage for each phase of each specified BES bus.	LOWER	None	None	Normal		TO	
PRC-002-2	R3.2.	Each phase current and the residual or neutral current for the following BES Elements:	LOWER	None	None	Normal		TO	
PRC-002-2	R3.2.1.	Transformers that have a low-side operating voltage of 100kV or above.	LOWER	None	None	Normal		TO	
PRC-002-2	R3.2.2.	Transmission Lines.	LOWER	None	None	Normal		TO	
PRC-002-2	R4.	Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following:	LOWER	None	None	Normal		TO	
PRC-002-2	R4.1.	A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.	LOWER	None	None	Normal		TO	
PRC-002-2	R4.2.	A minimum recording rate of 16 samples per cycle.	LOWER	None	None	Normal		TO	
PRC-002-2	R4.3.	Trigger settings for at least the following:	LOWER	None	None	Normal		TO	
PRC-002-2	R4.3.1.	Neutral (residual) overcurrent.	LOWER	None	None	Normal		TO	
PRC-002-2	R4.3.2.	Phase undervoltage or overcurrent.	LOWER	None	None	Normal		TO	
PRC-002-2	R6.	Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5:	LOWER	None	None	Normal		TO	
PRC-002-2	R6.1.	One phase-to-neutral or positive sequence voltage.	LOWER	None	None	Normal		TO	
PRC-002-2	R6.2.	The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.	LOWER	None	None	Normal		TO	
PRC-002-2	R6.3.	Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.	LOWER	None	None	Normal		TO	
PRC-002-2	R6.4.	Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.	LOWER	None	None	Normal		TO	
PRC-002-2	R8.	Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following:	LOWER	None	None	Normal		TO	
PRC-002-2	R8.1.	Triggered record lengths of at least three minutes.	LOWER	None	None	Normal		TO	

PRC-002-2	R8.2.	At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.	LOWER	None	None	Normal		TO	
PRC-002-2	R9.	Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following:	LOWER	None	None	Normal		TO	
PRC-002-2	R9.1.	Input sampling rate of at least 960 samples per second.	LOWER	None	None	Normal		TO	
PRC-002-2	R9.2.	Output recording rate of electrical quantities of at least 30 times per second.	LOWER	None	None	Normal		TO	
PRC-002-2	R10.	Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following:	LOWER	None	None	Normal		TO	
PRC-002-2	R10.1.	Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.	LOWER	None	None	Normal		TO	
PRC-002-2	R10.2.	Synchronized device clock accuracy within ± 2 milliseconds of UTC.	LOWER	None	None	Normal		TO	
PRC-002-2	R11.	Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following:	LOWER	None	None	Normal		TO	
PRC-002-2	R11.1.	Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.	LOWER	None	None	Normal		TO	
PRC-002-2	R11.2.	Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.	LOWER	None	None	Normal		TO	
PRC-002-2	R11.3.	SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.	LOWER	None	None	Normal		TO	
PRC-002-2	R11.4.	FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.	LOWER	None	None	Normal		TO	
PRC-002-2	R11.5.	Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.	LOWER	None	None	Normal		TO	
PRC-002-2	R12.	Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) to the Regional Entity and implement	LOWER	None	None	Normal		TO	
PRC-004-5(i)	R1.	Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: 1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.	HIGH	None	None	Normal		TO	
PRC-004-5(i)	R2.	Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. 2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: 2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and 2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and 2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation	HIGH	None	None	Normal		TO	

PRC-004-5(i)	R3.	Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.	HIGH	None	None	Normal		TO	
PRC-004-5(i)	R4.	Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or	HIGH	None	None	Normal		TO	
PRC-004-5(i)	R5.	Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	HIGH	None	None	Normal		TO	
PRC-004-5(i)	R6.	Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	HIGH	None	None	Normal		TO	
PRC-005-1.1b	R1.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:	HIGH	None	None	Normal		TO	
PRC-005-1.1b	R1.1.	Maintenance and testing intervals and their basis.	HIGH	None	None	Normal		TO	
PRC-005-1.1b	R1.2.	Summary of maintenance and testing procedures.	HIGH	None	None	Normal		TO	
PRC-005-1.1b	R2.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Entity on request (within 30 calendar days). The documentation of the program implementation shall include:	LOWER	None	None	Normal		TO	
PRC-005-1.1b	R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	HIGH	None	None	Normal		TO	
PRC-005-1.1b	R2.2.	Date each Protection System device was last tested/maintained.	HIGH	None	None	Normal		TO	
PRC-005-6	R1.	Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities.	MEDIUM	None	None	Normal		TO	
PRC-005-6	R2.	Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals.	MEDIUM	None	None	Normal		TO	
PRC-005-6	R3.	Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5.	HIGH	None	None	Normal		TO	

PRC-005-6	R4.	Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s).	HIGH	None	None	Normal		TO	
PRC-005-6	R5.	Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues.	MEDIUM	None	None	Normal		TO	
PRC-006-3	R8.	Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	LOWER	None	None	Normal		TO	
PRC-006-3	R9.	Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets.	HIGH	None	None	Normal		TO	
PRC-006-3	R10.	Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	HIGH	None	None	Normal		TO	
PRC-006-SERC-02	R4.	Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year.	MEDIUM	None	None	Normal		TO	
PRC-006-SERC-02	4.1.	The percent of load shedding to be implemented shall be based on the actual or estimated substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year's actual Peak Demand in the season specified by the Planning Coordinator in R2.	MEDIUM	None	None	Normal		TO	
PRC-006-SERC-02	4.2.	The amount of load in each load shedding step shall be within -1.0 and +3.0 of the percentage specified by the Planning Coordinator (for example, if the specified percentage step load shed is 12%, the allowable range is 11 to 15%).	MEDIUM	None	None	Normal		TO	
PRC-006-SERC-02	4.3.	The amount of total UFLS load of all steps combined shall be within -1.0 and +5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.	MEDIUM	None	None	Normal		TO	
PRC-006-SERC-02	R5.	Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator, but shall not be required to have more than one UFLS step. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year.	MEDIUM	None	None	Normal		TO	
PRC-006-SERC-02	5.1.	The percent of load shedding to be implemented shall be based on the actual or estimated substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year actual Peak Demand in the season specified by the Planning Coordinator in R2.	MEDIUM	None	None	Normal		TO	
PRC-006-SERC-02	5.2.	The amount of total UFLS load shall be within ± 5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.	MEDIUM	None	None	Normal		TO	
PRC-006-SERC-02	R6.	Each UFLS entity shall implement changes to the UFLS scheme which involve frequency settings, relay time delays, changes to the percentage of load in the scheme, or changes to the peak season selected in R2.1 within 18 months of notification by the Planning Coordinator.	HIGH	None	None	Normal		TO	
PRC-008-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.	MEDIUM	None	None	Normal		TO	
PRC-010-2	R2.	Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5.	HIGH	None	None	Normal		TO	
PRC-010-2	R7.	Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database.	LOWER	None	None	Normal		TO	
PRC-011-0	R1.	The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.1.	The UVLS system identification which shall include but is not limited to:	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.1.1.	Relays.	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.1.2.	Instrument transformers.	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.1.3.	Communications systems, where appropriate.	MEDIUM	None	None	Normal		TO	

PRC-011-0	R1.1.4.	Batteries.	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.3.	Summary of testing procedure.	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.4.	Schedule for system testing.	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.5.	Schedule for system maintenance.	MEDIUM	None	None	Normal		TO	
PRC-011-0	R1.6.	Date last tested/maintained.	MEDIUM	None	None	Normal		TO	
PRC-011-0	R2.	The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).	LOWER	None	None	Normal		TO	
PRC-012-2	R1.	Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.	MEDIUM	None	None	Normal		TO	
PRC-012-2	R3.	Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.	MEDIUM	None	None	Normal		TO	
PRC-012-2	R5.	Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: 5.1. Participate in analyzing the RAS operational performance to determine whether: 5.1.1. The System events and/or conditions appropriately triggered the RAS. 5.1.2. The RAS responded as designed. 5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address. 5.1.4. The RAS operation resulted in any unintended or adverse BES response. 5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).	MEDIUM	None	None	Normal		TO	
PRC-012-2	R6.	Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: · *Being notified of a deficiency in its RAS pursuant to Requirement R4, or* · *Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or* · *Identifying a deficiency in its RAS pursuant to Requirement R8.*	MEDIUM	None	None	Normal		TO	
PRC-012-2	R7.	Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *7.1. Implement the CAP.* *7.2. Update the CAP if actions or timetables change.* *7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.*	MEDIUM	None	None	Normal		TO	
PRC-012-2	R8.	Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: · *At least once every six full calendar years for all RAS not designated as limited impact, or* · *At least once every twelve full calendar years for all RAS designated as limited impact*	HIGH	None	None	Normal		TO	
PRC-015-1	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	MEDIUM	None	None	Normal		TO	
PRC-015-1	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	MEDIUM	None	None	Normal		TO	
PRC-015-1	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	LOWER	None	None	Normal		TO	

PRC-016-1	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	MEDIUM	None	None	Normal		TO	
PRC-016-1	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	MEDIUM	None	None	Normal		TO	
PRC-016-1	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	LOWER	None	None	Normal		TO	
PRC-017-1	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	HIGH	None	None	Normal		TO	
PRC-017-1	R1.1.	RAS identification shall include but is not limited to:	HIGH	None	None	Normal		TO	
PRC-017-1	R1.1.1.	Relays.	HIGH	None	None	Normal		TO	
PRC-017-1	R1.1.2.	Instrument transformers.	HIGH	None	None	Normal		TO	
PRC-017-1	R1.1.3.	Communications systems, where appropriate.	HIGH	None	None	Normal		TO	
PRC-017-1	R1.1.4.	Batteries.	HIGH	None	None	Normal		TO	
PRC-017-1	R1.2.	Documentation of maintenance and testing intervals and their basis.	HIGH	None	None	Normal		TO	
PRC-017-1	R1.3.	Summary of testing procedure.	HIGH	None	None	Normal		TO	
PRC-017-1	R1.4.	Schedule for system testing.	HIGH	None	None	Normal		TO	
PRC-017-1	R1.5.	Schedule for system maintenance.	HIGH	None	None	Normal		TO	
PRC-017-1	R1.6.	Date last tested/maintained.	MEDIUM	None	None	Normal		TO	
PRC-017-1	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	LOWER	None	None	Normal		TO	
PRC-018-1	R1.	Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:	LOWER	None	None	Normal		TO	
PRC-018-1	R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	LOWER	None	None	Normal		TO	
PRC-018-1	R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days.	LOWER	None	None	Normal		TO	
PRC-018-1	R2.	The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).	LOWER	None	None	Normal		TO	
PRC-018-1	R3.	The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):	LOWER	None	None	Normal		TO	
PRC-018-1	R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	LOWER	None	None	Normal		TO	
PRC-018-1	R3.2.	Make and model of equipment.	LOWER	None	None	Normal		TO	
PRC-018-1	R3.3.	Installation location.	LOWER	None	None	Normal		TO	
PRC-018-1	R3.4.	Operational status.	LOWER	None	None	Normal		TO	
PRC-018-1	R3.5.	Date last tested.	LOWER	None	None	Normal		TO	
PRC-018-1	R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	LOWER	None	None	Normal		TO	
PRC-018-1	R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	LOWER	None	None	Normal		TO	
PRC-018-1	R3.8.	Monitored electrical quantities, such as voltage, current, etc.	LOWER	None	None	Normal		TO	
PRC-018-1	R4.	The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).	LOWER	None	None	Normal		TO	

PRC-018-1	R5.	The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	LOWER	None	None	Normal		TO	
PRC-018-1	R6.	Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	LOWER	None	None	Normal		TO	
PRC-018-1	R6.1.	Maintenance and testing intervals and their basis.	LOWER	None	None	Normal		TO	
PRC-018-1	R6.2.	Summary of maintenance and testing procedures.	LOWER	None	None	Normal		TO	
PRC-019-2	R1.	At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. [See footnote]	MEDIUM	None	None	Normal		TO	
PRC-019-2	1.1.	Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:	MEDIUM	None	None	Normal		TO	
PRC-019-2	1.1.1.	The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.	MEDIUM	None	None	Normal		TO	
PRC-019-2	1.1.2.	The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.	MEDIUM	None	None	Normal		TO	
PRC-019-2	R2.	Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following • Voltage regulating settings or equipment changes; • Protection System settings or component changes; • Generating or synchronous condenser equipment capability changes; or • Generator or synchronous condenser step-up transformer changes.	MEDIUM	None	None	Normal		TO	
PRC-023-4	R1.	Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. **See standard for Criteria.**	HIGH	None	None	Normal		TO	
PRC-023-4	R2.	Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.	HIGH	None	None	Normal		TO	
PRC-023-4	R3.	Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.	MEDIUM	None	None	Normal		TO	
PRC-023-4	R4.	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports.	LOWER	None	None	Normal		TO	
PRC-023-4	R5.	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability.	LOWER	None	None	Normal		TO	
PRC-025-1	R1.	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	HIGH	None	None	Normal		TO	
PRC-025-2	R1.	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	HIGH	None	None	Normal		TO	

PRC-026-1	R1.	Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology based on an angular stability constraint. 3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability. 4. An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance.	MEDIUM	None	None	Normal		TO	
PRC-026-1	R2.	Each Generator Owner and Transmission Owner shall: (please see standard for sub-req's) 2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-1 – Attachment B criteria has not been performed in the last five calendar years. 2.2 Within 12 full calendar months of becoming aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B.	HIGH	None	None	Normal		TO	
PRC-026-1	R3.	Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: • The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or • The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).	MEDIUM	None	None	Normal		TO	
PRC-026-1	R4.	Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete.	MEDIUM	None	None	Normal		TO	
TOP-001-4	R1.	Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.	HIGH	None	Normal	Normal			TOP
TOP-001-4	R2.	Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.	HIGH	Normal See CFR00001	Normal	Normal	BA		
TOP-001-4	R3.	Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.	HIGH	Full See CFR00001	None	None	BA		
TOP-001-4	R4.	Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.	HIGH	Full See CFR00001	None	None	BA		
TOP-001-4	R5.	Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.	HIGH	None	Normal	Normal			TOP
TOP-001-4	R6.	Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.	HIGH	None	Normal	Normal			TOP