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Project 2017-01 Modifications to BAL-003-1.1

Technical Workshop
March 26, 2019

RELIABILITY | ACCOUNTABILITY




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Administrative Items

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Agenda

- Welcome and Introductions - **Laura Anderson**, NERC Standards Developer
- Project Overview – **David Lemmons**, Ethos Energy
- Panel 1 – Interconnection Frequency Response Obligation
- Panel 2 – Frequency Response Measure Panel 3 – Existing Allocation and Alternate Methods
- Panel 4 – Applicable NERC Registered Entities
- Phase II Q&A Session

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Interconnection Frequency Response Obligation (IFRO)

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March 26, 2019

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Background and Current Methodology

- Resource Loss Protection Criteria (RLPC) is the designed resource loss used to determine
  - Interconnection Frequency Response Obligation (IFRO)
  - Several terms used in the past for this concept
- Goal is to avoid underfrequency loadshedding
- "N-2" event has been used to determine RLPC
  - Leads to two or more electrical facilities removed from service
  - Breaker failures, bus faults, double circuit tower outages, etc.
- Eastern Interconnection uses worst event in previous 10 years
- Inconsistencies with current methodology
  - Eastern Interconnection event that is used did not occur in previous 10 years
  - Western Interconnection Remedial Action Scheme (RAS) events exceed the RLPC

Existing Processes and Terms

- Single Contingency or N-1 Event (paraphrased from FAC-011-3)
  - Loss of generator, line, transformer, or shunt device
  - Single pole block in a monopolar or bipolar High-Voltage Direct Current (HVDC) system
  - Loss of asynchronous Direct Current (DC) tie
- Balancing Contingency Event (BCE)
  - Single events (N-1) or series of events separated by one minute or less
  - Sudden loss of import resulting in imbalance between generation and demand on the Interconnection (frequency change)
- Most Severe Single Contingency (MSSC)
  - BCE due to a single contingency (N-1) that results in the greatest resource loss (MegaWatt (MW)) to a Balancing Authority (BA)
- Interconnection
  - Western, Eastern, Quebec, ERCOT

RLPC Proposal

- Single Contingency (N-1) Events
  - The two largest individual Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the Balancing Authority (BA) Area, regardless of shared ownership/responsibility.
  - Multi-ownership resources will need to determine a single reporting BA
  - Full rating of the resource should be reported
- The two largest values are reported on Frequency Response Standard (FRS) Form 1

RLPC Proposal

- Resource loss due to RAS initiated by multiple contingency (N-2)
  - RAS affecting multiple BAs should be reported by a single BA
  - N-2 RAS is reported on FRS Form 1
- FRS Form 1 Data Contains (for each BA)
  - Largest potential resource loss due to N-1 event
  - Second largest potential resource loss due to N-1 event
  - Largest resource loss due to RAS initiated by N-2 event
- For each Interconnection
  - Largest and second largest potential resource losses are summed
  - Largest resource loss due to RAS initiated by N-2 event is compared to sum
  - Larger value becomes RLPC
- Calculated RLPC should equal or exceed any credible N-2 event

Example Four BA Interconnection

BA1	Resource Loss A = 1200 MW	Both at same plant (N-2)
	Resource Loss B = 1200 MW	
BA2	Resource Loss A = 1400 MW	Electrically separate
	Resource Loss B = 1000 MW	
BA3	Resource Loss A = 1000 MW	Electrically separate
	Resource Loss B = 800 MW	
BA4	Resource Loss A = 1500 MW (DC TIE)	Electrically separate
	Resource Loss B= 500 MW	

- Largest resource loss = 1500 MW
- Second largest resource loss = 1400 MW
- RAS initiated by N-2 = 0 MW
- Summation of two largest resource losses = 2900 MW
  - Largest N-2 resource loss = 2400 MW
- RLPC = 2900 MW

Example Three BA Interconnection with RAS

BA1	RAS = 2850 MW	N-2 RAS event
	Resource Loss A = 1150 MW	Electrically separate
	Resource Loss B = 800 MW	
BA2	Resource Loss A = 1380 MW	Both at same plant (N-2)
	Resource Loss B = 1380 MW	
BA3	Resource Loss A = 800 MW	Electrically separate
	Resource Loss B = 700 MW	

- Largest resource loss = 1380 MW
- Second largest resource loss = 1380 MW
- RAS initiated by N-2 = 2850 MW
- Summation of two largest resource losses = 2760 MW
  - Largest N-2 resource loss = 2760 MW
- RLPC = 2850 MW

Interconnection RLPC Values

Eastern Interconnection

Present RLPC = 4500 MW

RESOURCE LOSS A = 1732 MW

RESOURCE LOSS B = 1477 MW

Proposed RLPC = 3209 MW

Western Interconnection

Present RLPC = 2626 MW

RESOURCE LOSS A = 1505 MW

RESOURCE LOSS B = 1344 MW

N-2 RAS = 2850 MW

Proposed RLPC = 2850 MW

Interconnection RLPC Values

ERCOT

Present RLPC = 2750 MW

RESOURCE LOSS A = 1375 MW

RESOURCE LOSS B = 1375 MW

Proposed RLPC = 2750 MW

Quebec Interconnection

Present RLPC = 1700 MW

RESOURCE LOSS A = 1000 MW

RESOURCE LOSS B = 1000 MW

Proposed RLPC = 2000 MW

IFRO Calculation

Calculation of IFRO values using RLPC:

- IFRO = $\frac{(RLPC-CLR)}{(MDF*10)}$ in MW/0.1Hz
- MDF is the Maximum Delta Frequency for the specific Interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA)

Interconnection Frequency Response Obligation

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	0.420	0.280	0.405	0.947	Hz
Resource Loss Protection Criteria (RLPC)	3,209	2,850	2,750	2,000	MW
Credit for Load Resources (CLR)			1,209		MW
Calculated IFRO	-764	-1018	-381	-211	MW/0.1Hz

Note: The proposed reduction in the Eastern Interconnection IFRO will be phased in over a three-year period.

IFRO Calculation

Determination of MDF from 2017 FRAA

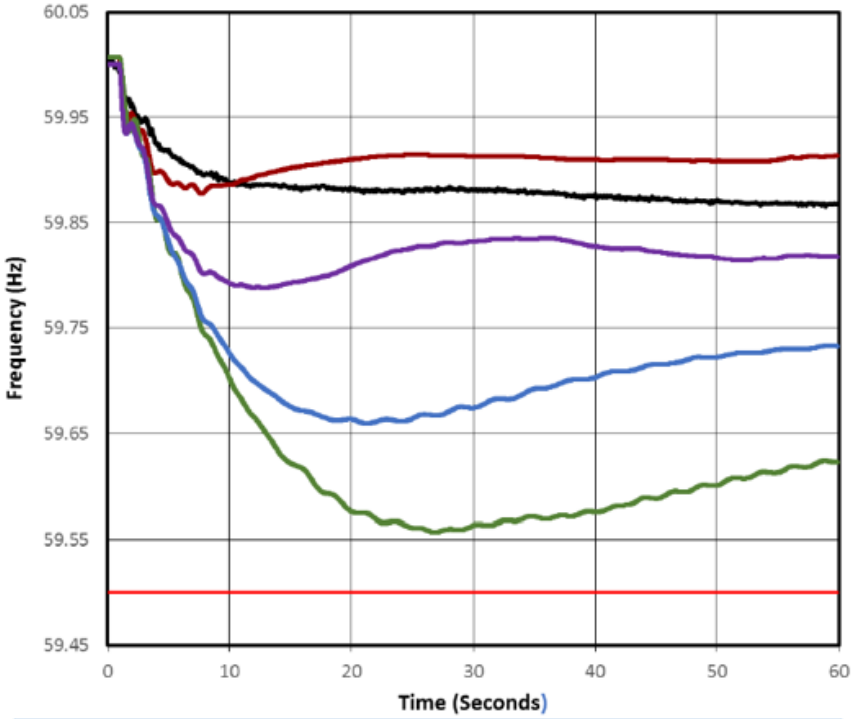
Table 2.4: Determination of Maximum Allowable Delta Frequencies					
	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.966	59.968	59.967	Hz
Minimum Frequency Limit	59.500	59.500	59.300	58.500	Hz
Base Delta Frequency	0.474	0.467	0.667	1.468	Hz
CB_R[26]	1.111	1.670	1.648	1.550	Ratio
Delta Frequency (DF_{CBR})[27]	0.427	0.280	0.405	0.947	Hz
BC'_{ADJ}[28]	0.007	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	0.420	0.280	0.405	0.947	Hz

IFRO Validation

NERC will validate proposed IFRO's using similar methods

- Light Load Base Case assumptions
  - Base Case Load Level
  - Base Case Inertia
  - Total online Generation capacity
  - Total online IBR Generation Capacity
  - Total online Capacity of Frequency Responsive Generation
  - % Online Spinning Reserves
  - % Online Frequency Responsive Reserves

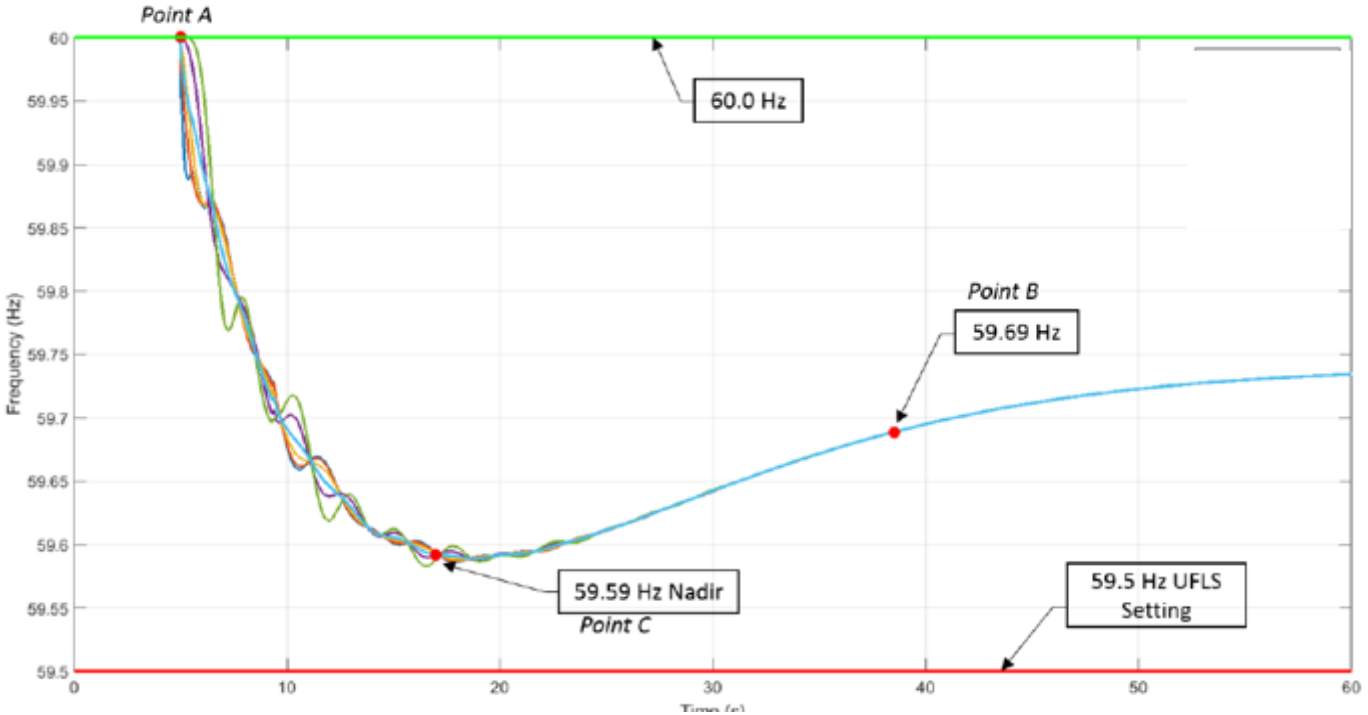
IFRO Validation Method



Detune Level	% Online Frequency Responsive Reserves
Level 1	25%
Level 2	20%
Level 3	15%
Level 4	10%

IFRO Validation Method

- Determine Points A, B, & C
- Calculate resulting IFRM from detuned case
- Ensure adequate margin exists between Point C & UFLS



Questions and Answers

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Frequency Response Measure (FRM)

Considerations on changes to the FRM

BAL-003 Drafting Team members:
Rich Hydzik (moderator), Terry Bilke, Greg Park, Danielle Croop, Josh Boone, and Tom Pruitt

Project 2017-01 Modifications to BAL-003-1.1 Technical Conference
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Panel Questions

- What improvements are needed based on Interconnections performance under the existing BAL-003-1.1?
- Do reliability needs dictate separate measures for Arresting, Stabilizing (current method), and Recovering periods?
- Do the use and application of adjustments (e.g., non-conforming load, dynamic schedules, etc.) need more clarification? Do we need to add other adjustments?
- What are the pitfalls of delta NAI to measure FRM? Are there viable alternatives?
- How can we best simplify the data collection and submittal process?
- Should measurement also include a prospective Frequency Response Reserve (FRR) requirement?

Need for New Requirements?

- What areas of historical performance indicate a need for improvement?
  - We have seen an improvement in B space with either no change or slight improvement in C space (FRAA Report)
  - Interconnection nadirs (C point) are constant or increasing
- Particularly in light of a changing resource mix, what areas of performance in the future need to be addressed?

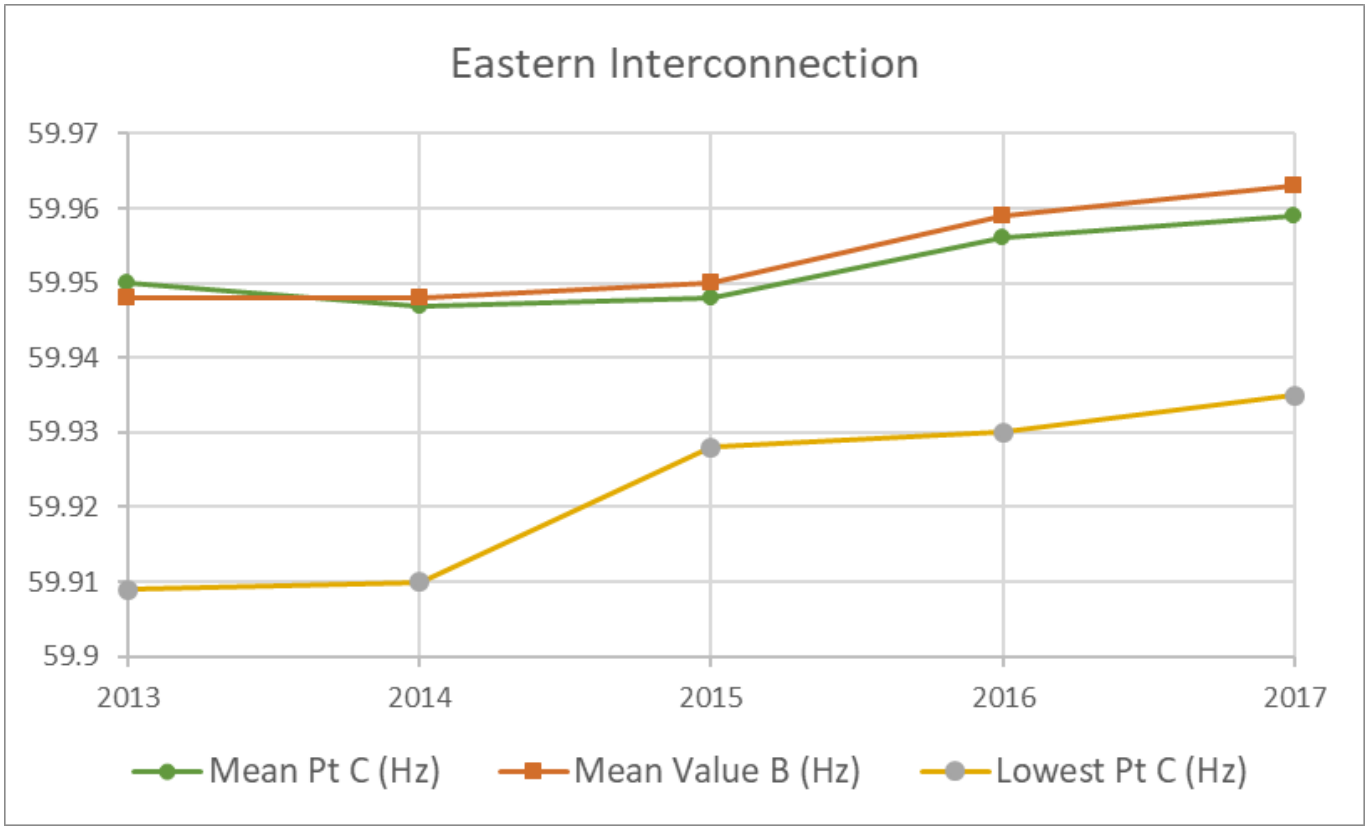
Current Frequency Performance

- 2018 State of Reliability Report – Improvement in B space with either no change or slight improvement in C space

Table E.2: Frequency Event Statistics for Eastern Interconnection									
Operating Year	Total Low Frequency Events	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (mHz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (mHz)
2013	32	1,157	60.000	59.950	59.948	-0.001	0.450	59.909	0.409
2014	34	1,212	59.995	59.947	59.948	0.001	0.447	59.910	0.410
2015	36	1,103	59.996	59.948	59.950	0.002	0.448	59.928	0.428
2016	61	938	59.999	59.956	59.959	0.003	0.456	59.930	0.430
2017	79	851	60.003	59.959	59.963	0.004	0.459	59.935	0.435

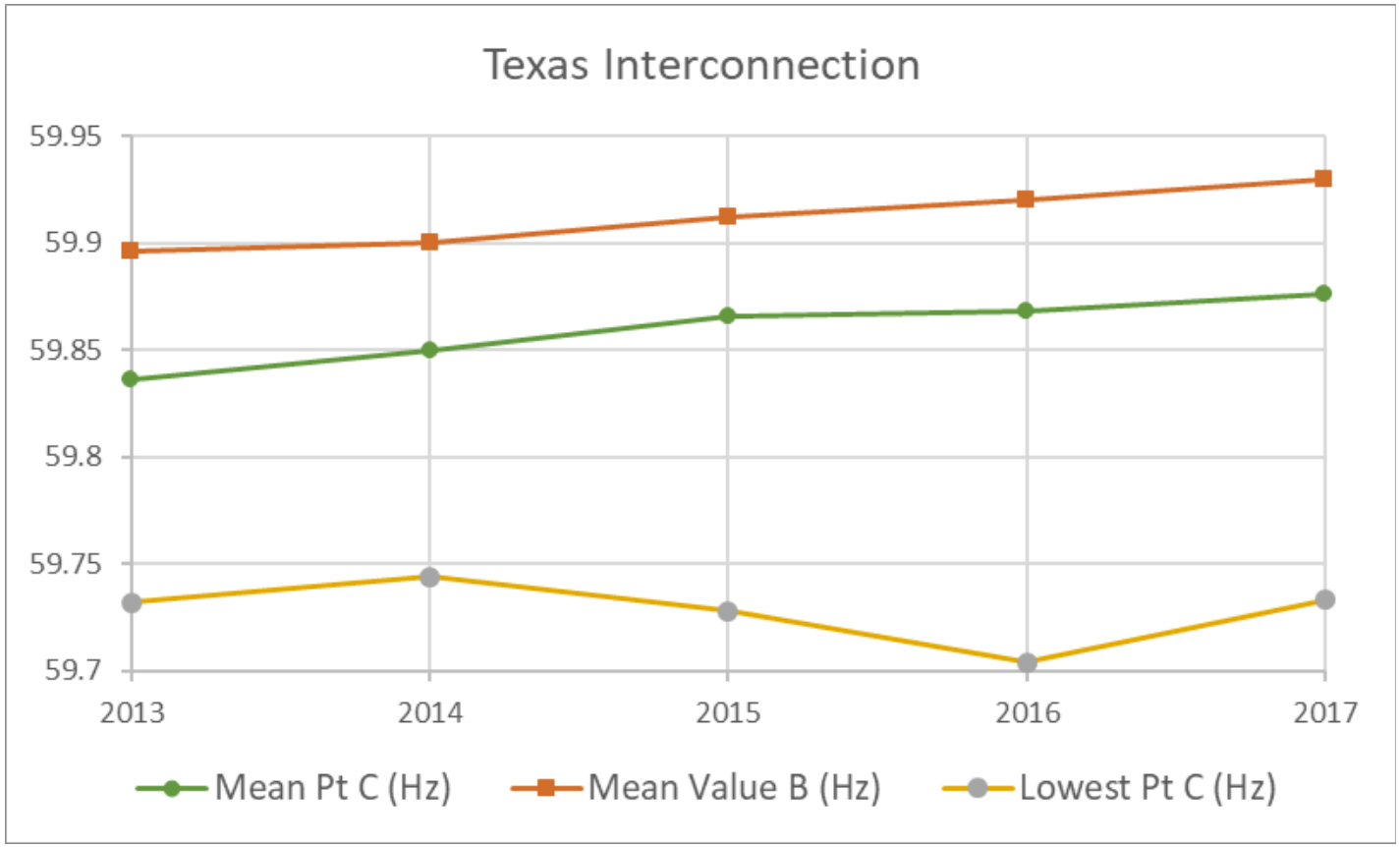
Eastern Interconnection Performance

- 2018 State of Reliability Report – Improvement in B space with either no change or slight improvement in C space



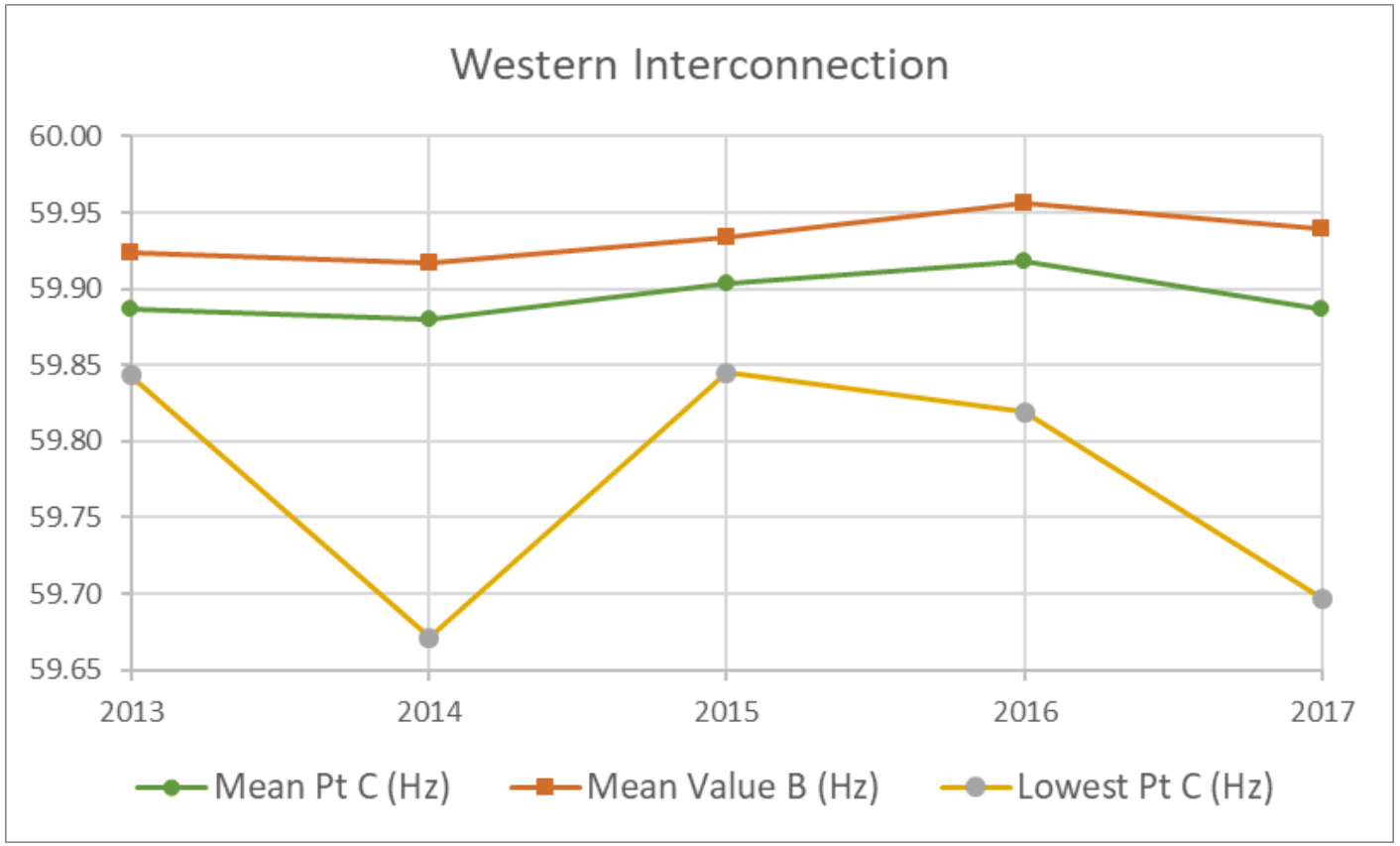
Texas Interconnection Performance

- 2018 State of Reliability Report – Improvement in B space with either no change or slight improvement in C space



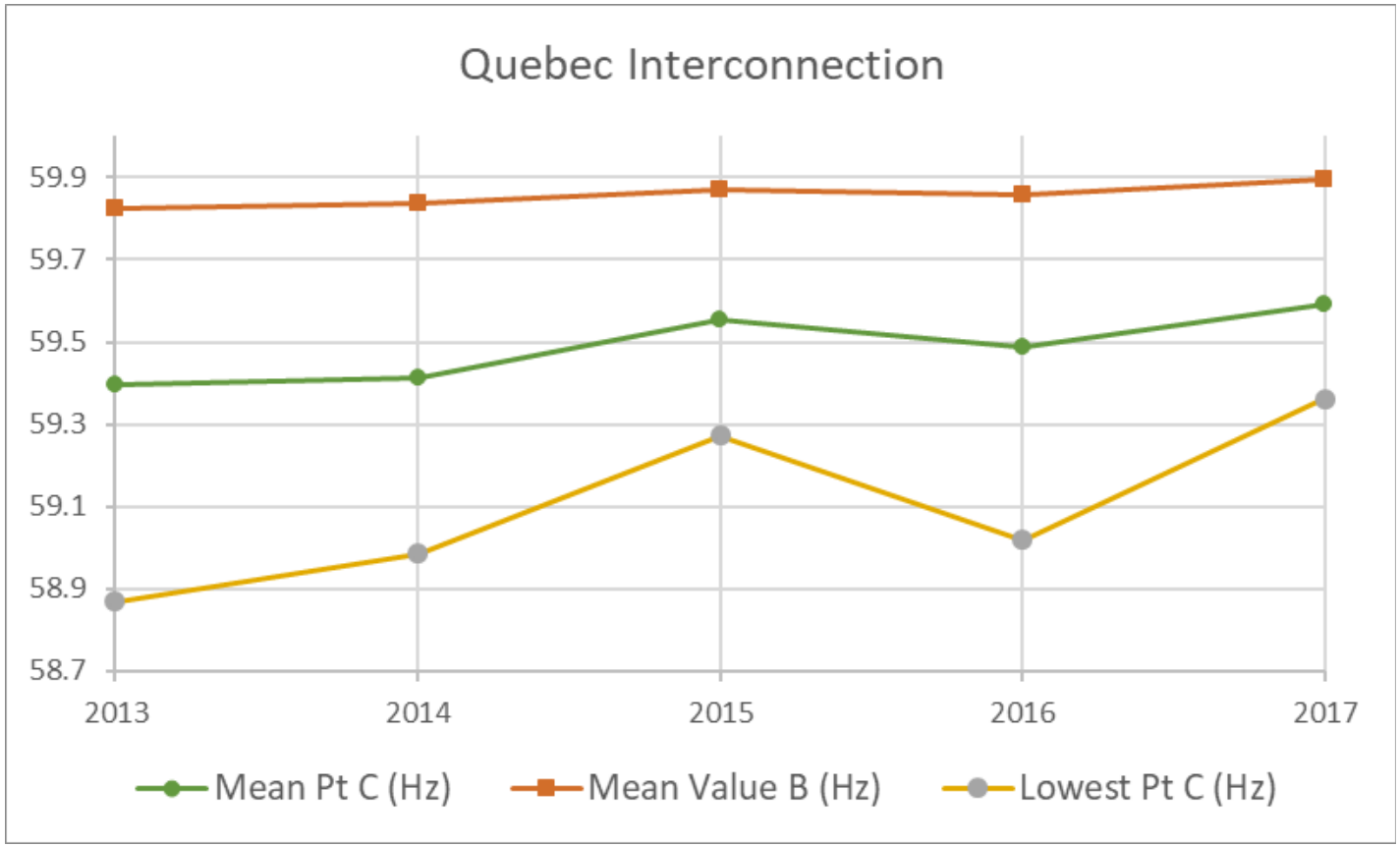
Western Interconnection Performance

- 2018 State of Reliability Report – Improvement in B space with either no change or slight improvement in C space



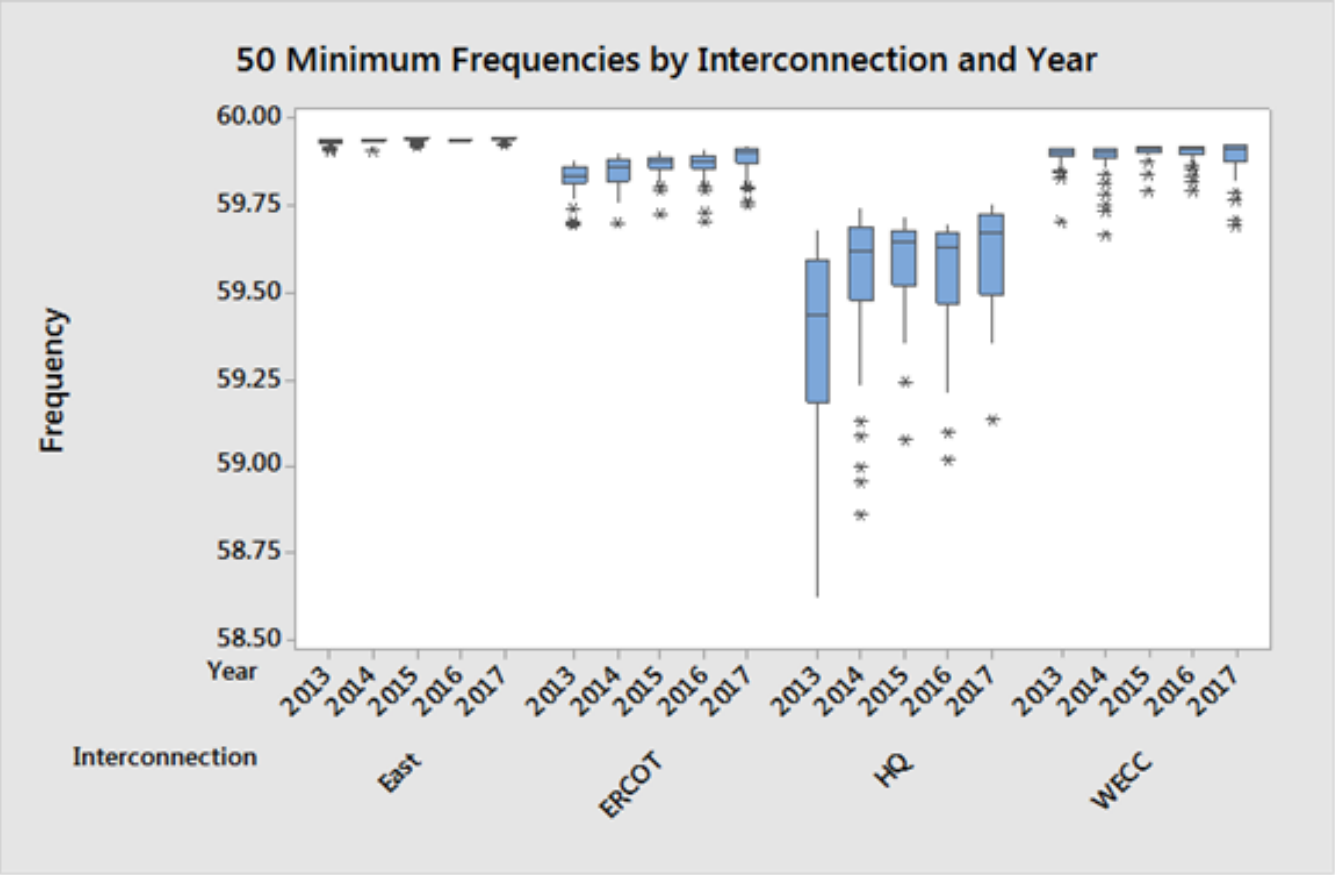
Quebec Interconnection Performance

- 2018 State of Reliability Report – Improvement in B space with either no change or slight improvement in C space



Minimum Frequency Trends

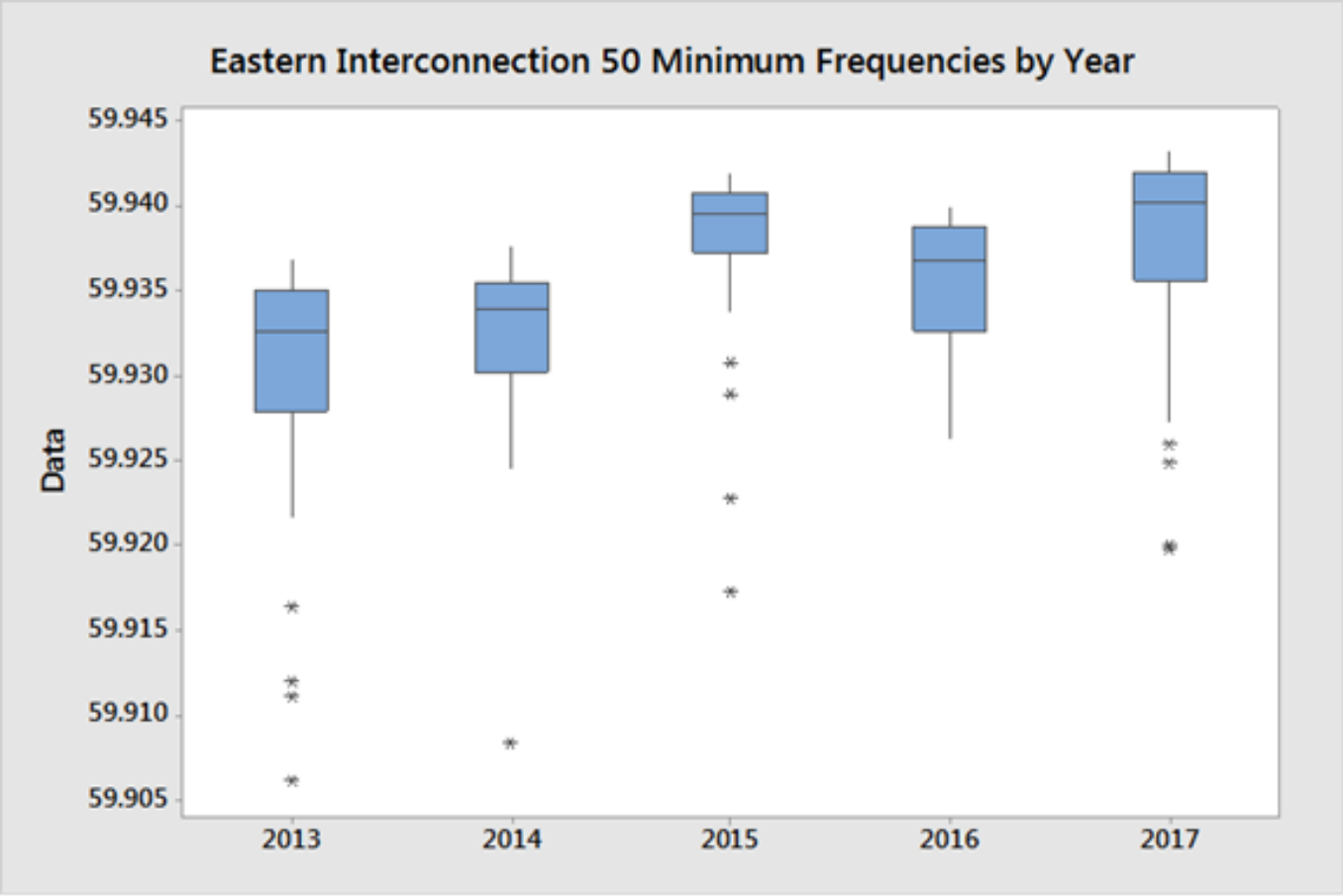
- BAL-003 intended to protect against reaching UFLS
- Minimum observed frequencies are stable or increasing



Source data: University of Tennessee FNet

Eastern Interconnection

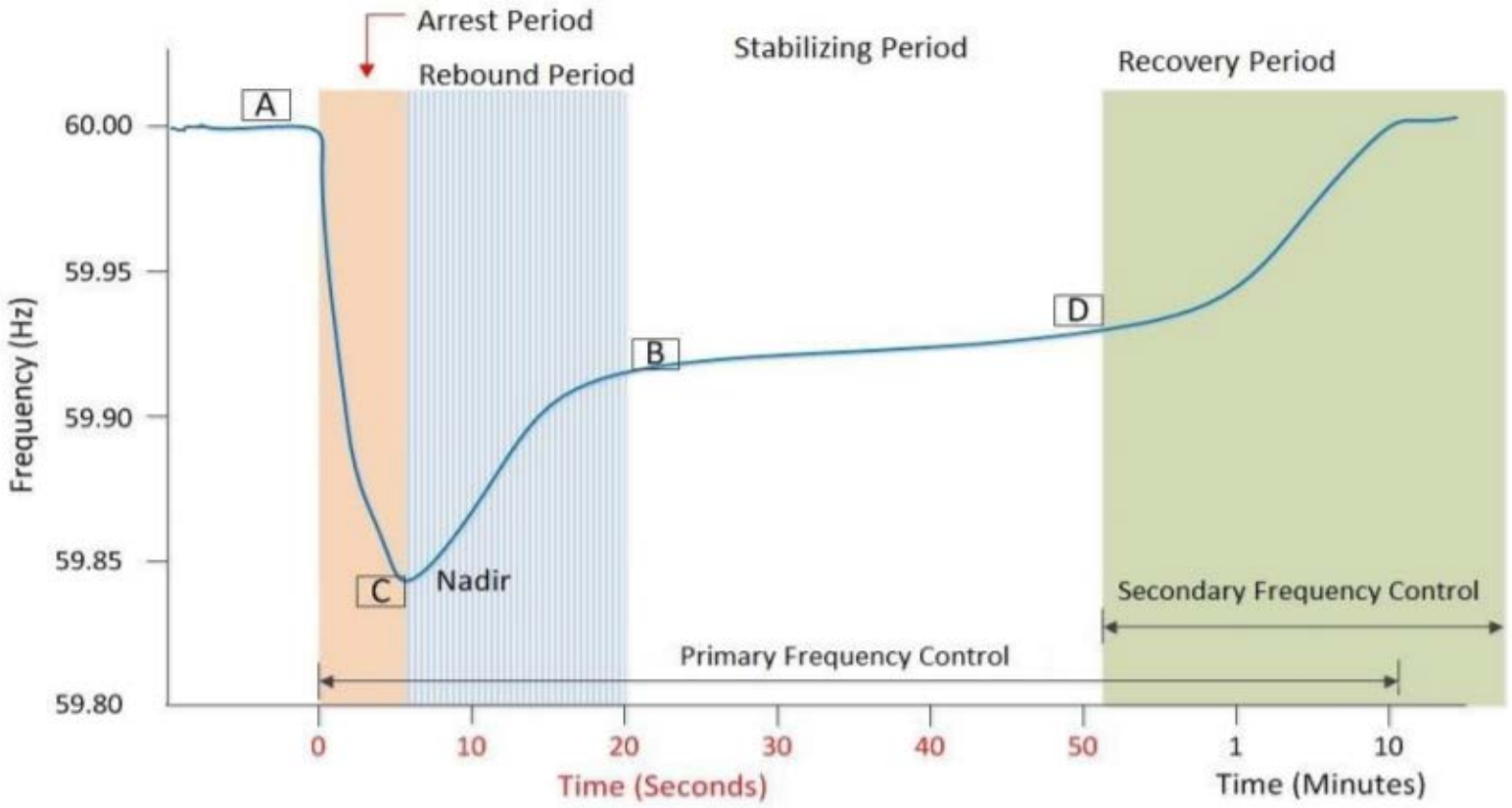
- Previous slide expanded to show East's performance



Separate Measures?

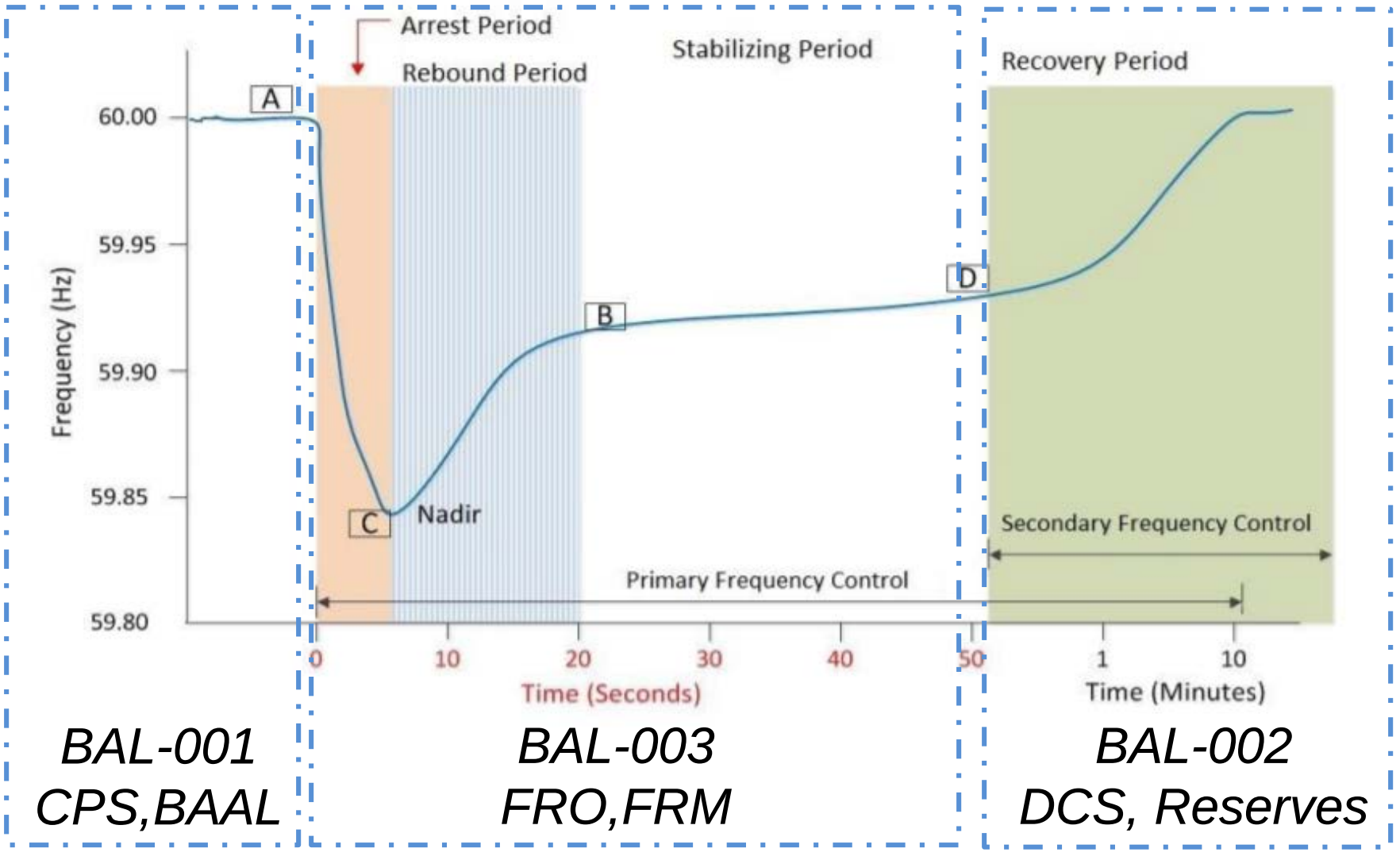
- Current standard does not inform BAs on how to address all stages of an event's impact to overall reliability. With an increase of new technologies, the 20-52 second period (~Stabilizing) may not clearly address all stages of an event.
- Is there a need for a metric for the arresting period and how would you measure this at the BA level?
- This would require MUCH higher speed data collection on the interties. What other challenges would there be?
- Does inertia need a metric to provide a minimum amount at the BA level as an "Arresting" measurement?
- Is there a need for a metric for the recovery period? Is this within the scope of BAL-003 or is there a need to modify other standards?

Separate Measures?



Value A	**Pre-disturbance Frequency**
Point C	**Nadir (maximum deviation)**
Value B	**Stabilizing Frequency**
Value D	**Recovery from Resource loss**

Separate Measures?



Adjustments

- Current adjustments
  - non-conforming load, dynamic schedules, jointly owned units, pumped storage units, contingent units, and FRM transfer
  - Some of these require sub-aggregation to effectively perform the response calculations
  - Can this process be simplified?
- BAL-003 implementation identified an unforeseen case
  - Some BAs negatively impacted by transmission losses
  - The drafting team is recommending an adjustment for these few cases
  - As in other adjustments, the BA must stay with the same approach for every BAL-003 event; not pick and choose

Losses Example

- In analyzing a single BA performance with three years of BAL-003 event data, Compliance could be predicted based upon location of resource loss relative to the majority of Frequency Responsive Resources within the Western Interconnection

Location of Resource loss and RESULTS	PREDICTABILITY	PREDICTED OUTCOME
Desert Southwest 9 OUT OF 15	60%	Coin Flip
Western US 15 OUT OF 19	79%	PASS
Colorado/Utah 18 OUT OF 22	**82%**	**FAIL**
Internal to the BA 13 OUT OF 13	100%	PASS

Loss Adjustment

Adjustment Clarification Needed

- Beyond losses, are there other adjustments needed?
- Schedule changes could be an option, but then all BAs would have to report their schedules with each other party so that performance can be validated
- Schedule changes, intentional dispatch of generation, wind tail off, load ramping and other Balancing Area operational concerns are not addressed in the current alternative methodologies

Data Collection / Submittal Simplification?

- Current measurement of frequency events require submittal via complex Excel spreadsheets. Is there a simplified data submittal process for compliance reporting?
- A “prototype” spreadsheet eliminating all the data/calculations that are not compliance related would be valuable
  - Screen shots of a draft are in the appendix
  - Eliminates the analyses and calculations not impacting current requirements (FRO, FRM, FBS)
  - Information not needed for compliance was excluded
  - The formulas reference data only in this workbook
  - This version has many of the “extra” features omitted or turned off (e.g., it does not yet do variable bias), but it does the basic calculations to determine the FRM and the FBS

Data Collection / Submittal Simplification?

- 1st tab is Data Entry tab copied from Form 1 – simply formulas (no formatting or hidden cells, rows, or columns)
- 2nd tab is essentially the Event Data in current Form 1 and the compilation of the Copy tab data in current Form 2s
- 3rd tab does the actual calculations to get the pre- and post-event data needed for the current Form 1. Data in rows 7-12 can be pasted as values to the preceding sheet
- Additional tabs (1/event) contain the raw event data (adjustments can be totaled). Intent is that each event data tab has a simple format to be exported as stand-alone CSVs or appended together into a single CSV. Transfer of this data would allow verification of the analysis and provide it for use in other analyses (e.g., FRAA, SoR)

Other Measures Needed?

- Would a FRR requirement ensure reliability going forward?
  - Hard to calculate load reserves, yet load provides PFR
  - Could be a large number if only addressing generation – 1MW of headroom does not = 1MW of PFR
  - Carrying reserves on a generator for PFR does not = PFR performance – we want performance
  - Having reserves is good, but getting PFR response is what is important
  - Spinning reserves are already being carried by BAs

- Do we need PFR performance measurement for GO?
  - A BA can set the generator up to respond (bring online, make headroom) but the GO needs to make sure they have the ability to respond.
  - Outer loop controls, squelching response needs to be addressed.
  - This cannot be addressed on a BA by BA basis – this is an Interconnection product
  - This is in-line with FERC Order 842- generators need to have the capability to respond

Questions and Answers

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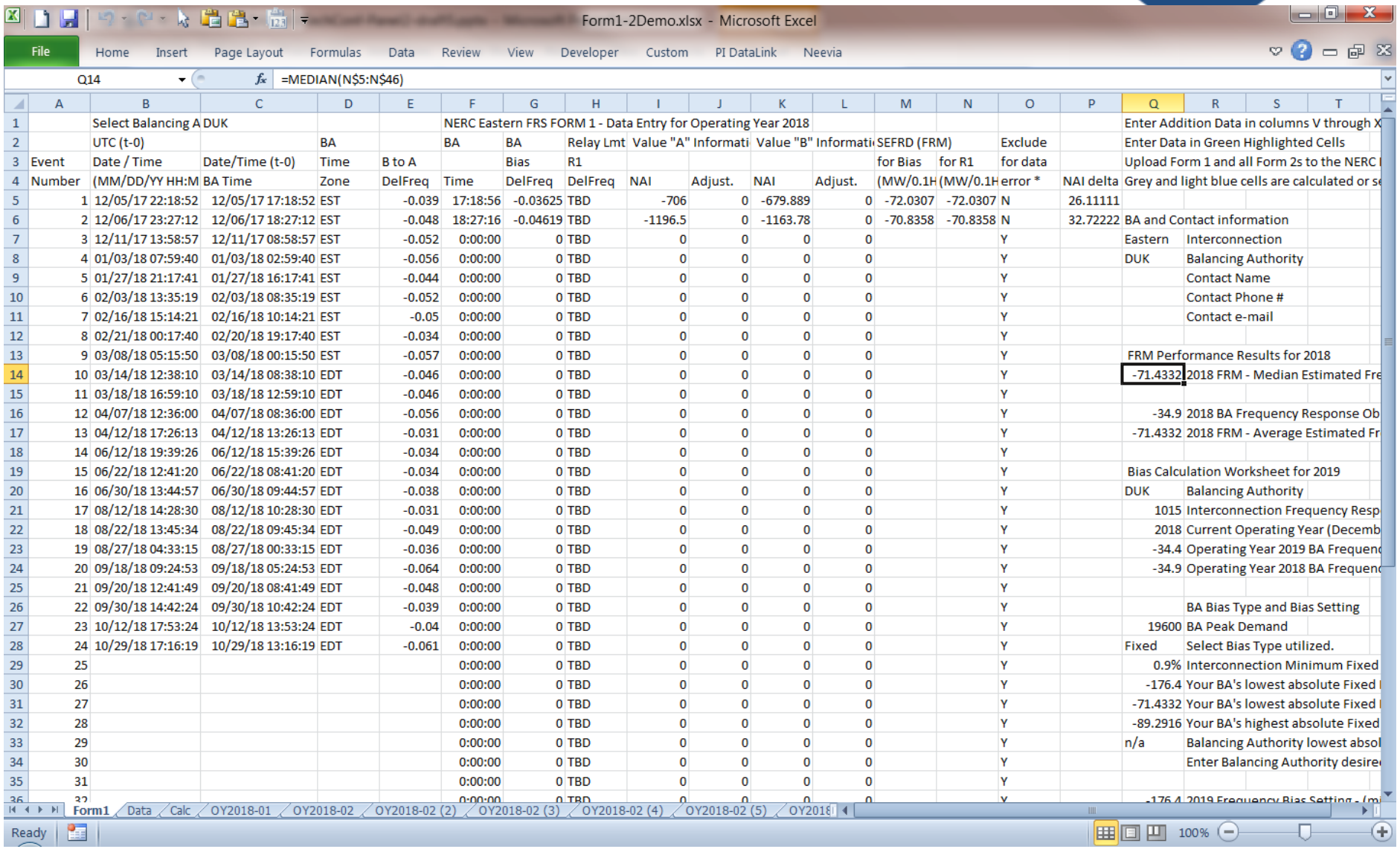
Data Collection / Submittal Simplification?


Form1-2Demo.xlsx - Microsoft Excel

File Home Insert Page Layout Formulas Data Review View Developer Custom PI DataLink Neevia

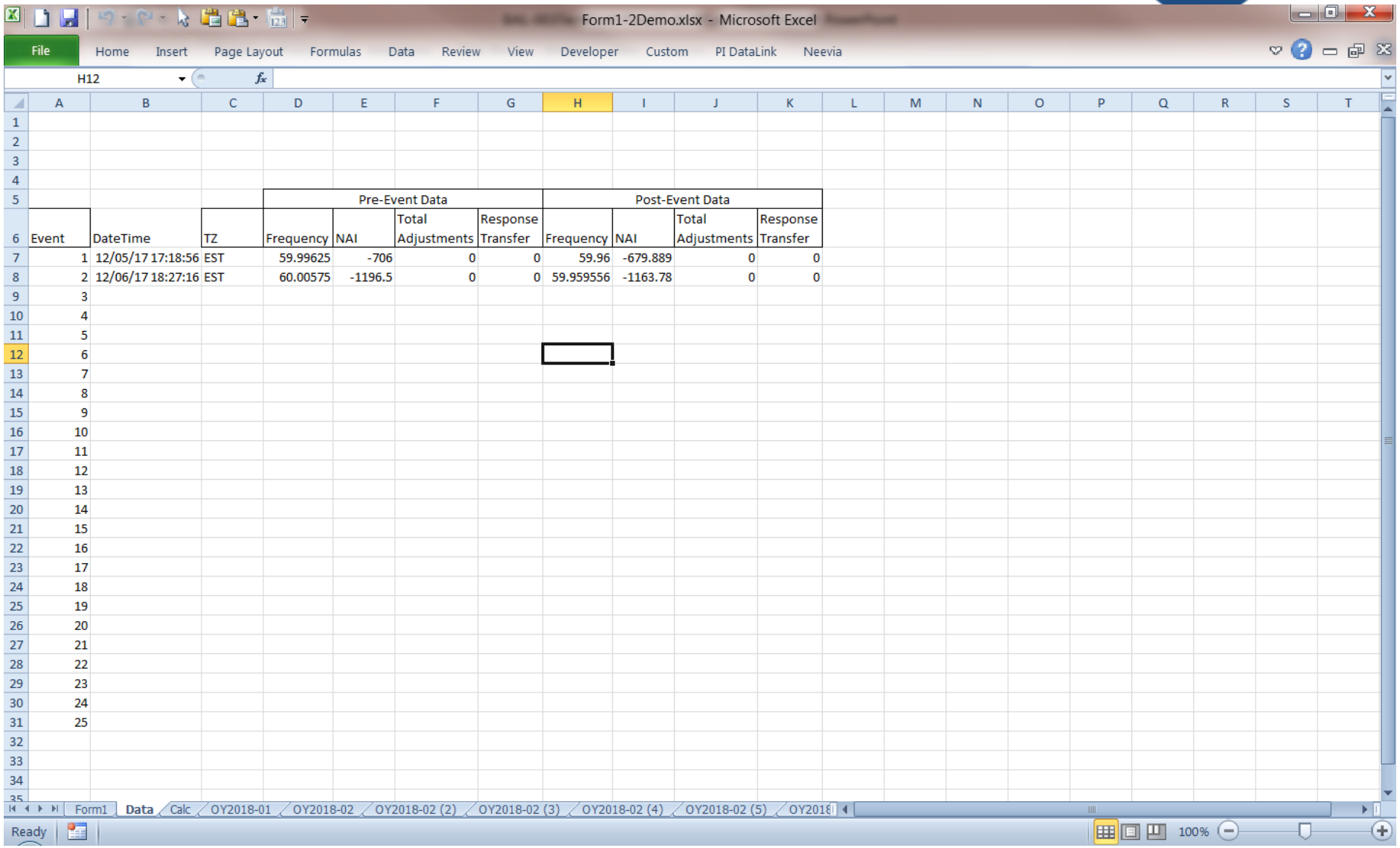
Q14 =MEDIAN(N$5:N$46)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1		Select Balancing A	DUK			NERC Eastern FRS FORM 1 - Data Entry for Operating Year 2018											Enter Addition Data in columns V through X			
2		UTC (t-0)		BA		BA	BA	Relay Lmt	Value "A" Informati		Value "B" Informati		SEFRD (FRM)		Exclude		Enter Data in Green Highlighted Cells			
3	Event	Date / Time	Date/Time (t-0)	Time	B to A		Bias	R1					for Bias	for R1	for data		Upload Form 1 and all Form 2s to the NERC			
4	Number	(MM/DD/YY HH:M	BA Time	Zone	DelFreq	Time	DelFreq	DelFreq	NAI	Adjust.	NAI	Adjust.	(MW/0.1H	(MW/0.1H	error *	NAI delta	Grey and light blue cells are calculated or se			
5	1	12/05/17 22:18:52	12/05/17 17:18:52	EST	-0.039	17:18:56	-0.03625	TBD	-706	0	-679.889	0	-72.0307	-72.0307	N	26.11111				
6	2	12/06/17 23:27:12	12/06/17 18:27:12	EST	-0.048	18:27:16	-0.04619	TBD	-1196.5	0	-1163.78	0	-70.8358	-70.8358	N	32.72222	BA and Contact information			
7	3	12/11/17 13:58:57	12/11/17 08:58:57	EST	-0.052	0:00:00	0	TBD	0	0	0	0			Y		Eastern	Interconnection		
8	4	01/03/18 07:59:40	01/03/18 02:59:40	EST	-0.056	0:00:00	0	TBD	0	0	0	0			Y		DUK	Balancing Authority		
9	5	01/27/18 21:17:41	01/27/18 16:17:41	EST	-0.044	0:00:00	0	TBD	0	0	0	0			Y			Contact Name		
10	6	02/03/18 13:35:19	02/03/18 08:35:19	EST	-0.052	0:00:00	0	TBD	0	0	0	0			Y			Contact Phone #		
11	7	02/16/18 15:14:21	02/16/18 10:14:21	EST	-0.05	0:00:00	0	TBD	0	0	0	0			Y			Contact e-mail		
12	8	02/21/18 00:17:40	02/20/18 19:17:40	EST	-0.034	0:00:00	0	TBD	0	0	0	0			Y					
13	9	03/08/18 05:15:50	03/08/18 00:15:50	EST	-0.057	0:00:00	0	TBD	0	0	0	0			Y		FRM Performance Results for 2018			
14	10	03/14/18 12:38:10	03/14/18 08:38:10	EDT	-0.046	0:00:00	0	TBD	0	0	0	0			Y		-71.4332	2018 FRM - Median Estimated Fre		
15	11	03/18/18 16:59:10	03/18/18 12:59:10	EDT	-0.046	0:00:00	0	TBD	0	0	0	0			Y					
16	12	04/07/18 12:36:00	04/07/18 08:36:00	EDT	-0.056	0:00:00	0	TBD	0	0	0	0			Y		-34.9	2018 BA Frequency Response Ob		
17	13	04/12/18 17:26:13	04/12/18 13:26:13	EDT	-0.031	0:00:00	0	TBD	0	0	0	0			Y		-71.4332	2018 FRM - Average Estimated Fr		
18	14	06/12/18 19:39:26	06/12/18 15:39:26	EDT	-0.034	0:00:00	0	TBD	0	0	0	0			Y					
19	15	06/22/18 12:41:20	06/22/18 08:41:20	EDT	-0.034	0:00:00	0	TBD	0	0	0	0			Y		Bias Calculation Worksheet for 2019			
20	16	06/30/18 13:44:57	06/30/18 09:44:57	EDT	-0.038	0:00:00	0	TBD	0	0	0	0			Y		DUK	Balancing Authority		
21	17	08/12/18 14:28:30	08/12/18 10:28:30	EDT	-0.031	0:00:00	0	TBD	0	0	0	0			Y		1015	Interconnection Frequency Resp		
22	18	08/22/18 13:45:34	08/22/18 09:45:34	EDT	-0.049	0:00:00	0	TBD	0	0	0	0			Y		2018	Current Operating Year (Decemb		
23	19	08/27/18 04:33:15	08/27/18 00:33:15	EDT	-0.036	0:00:00	0	TBD	0	0	0	0			Y		-34.4	Operating Year 2019 BA Frequenc		
24	20	09/18/18 09:24:53	09/18/18 05:24:53	EDT	-0.064	0:00:00	0	TBD	0	0	0	0			Y		-34.9	Operating Year 2018 BA Frequenc		
25	21	09/20/18 12:41:49	09/20/18 08:41:49	EDT	-0.048	0:00:00	0	TBD	0	0	0	0			Y					
26	22	09/30/18 14:42:24	09/30/18 10:42:24	EDT	-0.039	0:00:00	0	TBD	0	0	0	0			Y			BA Bias Type and Bias Setting		
27	23	10/12/18 17:53:24	10/12/18 13:53:24	EDT	-0.04	0:00:00	0	TBD	0	0	0	0			Y		19600	BA Peak Demand		
28	24	10/29/18 17:16:19	10/29/18 13:16:19	EDT	-0.061	0:00:00	0	TBD	0	0	0	0			Y		Fixed	Select Bias Type utilized.		
29	25					0:00:00	0	TBD	0	0	0	0			Y		0.9%	Interconnection Minimum Fixed		
30	26					0:00:00	0	TBD	0	0	0	0			Y		-176.4	Your BA's lowest absolute Fixed		
31	27					0:00:00	0	TBD	0	0	0	0			Y		-71.4332	Your BA's lowest absolute Fixed		
32	28					0:00:00	0	TBD	0	0	0	0			Y		-89.2916	Your BA's highest absolute Fixed		
33	29					0:00:00	0	TBD	0	0	0	0			Y		n/a	Balancing Authority lowest absol		
34	30					0:00:00	0	TBD	0	0	0	0			Y			Enter Balancing Authority desire		
35	31					0:00:00	0	TBD	0	0	0	0			Y					
36	32					0:00:00	0	TBD							Y		-176.4	2019 Frequency Bias Setting - (m		

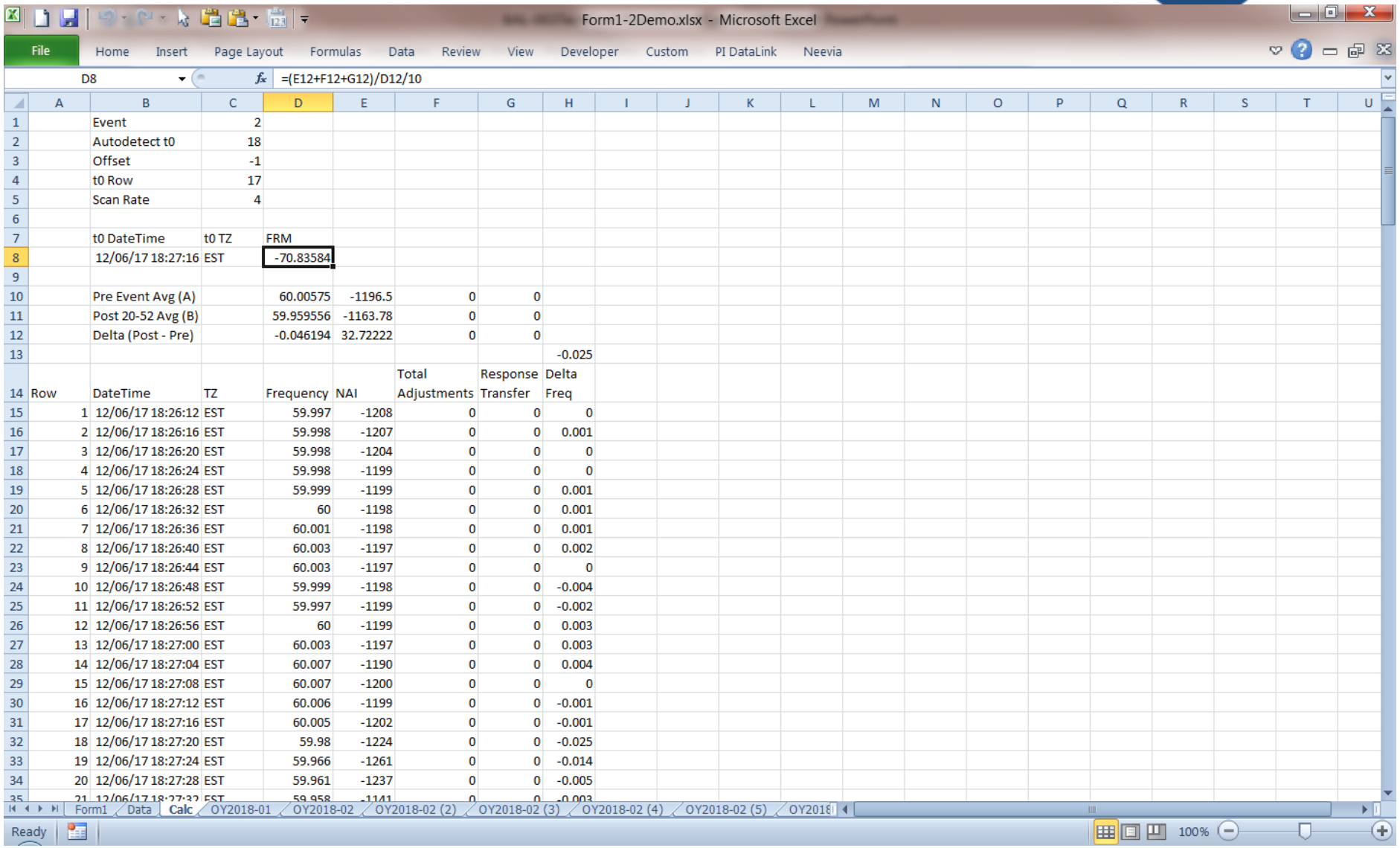
Form1 Data Calc OY2018-01 OY2018-02 OY2018-02 (2) OY2018-02 (3) OY2018-02 (4) OY2018-02 (5) OY2018

Ready 100%

Data Collection / Submittal Simplification?

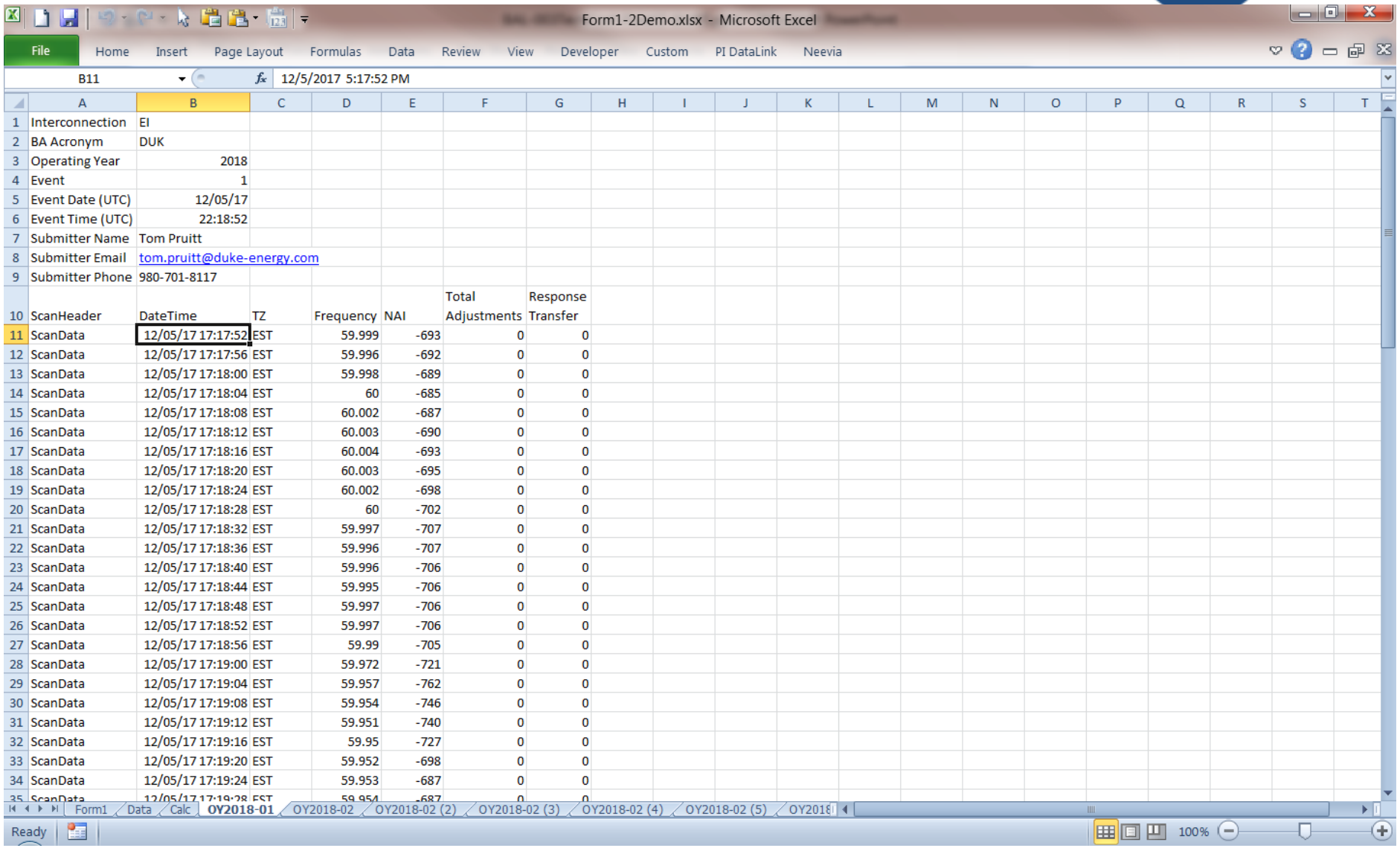


Data Collection / Submittal Simplification?



	A	B	C	D	E	F	G	H
1		Event	2					
2		Autodetect t0	18					
3		Offset	-1					
4		t0 Row	17					
5		Scan Rate	4					
6								
7		t0 DateTime	t0 TZ	FRM				
8		12/06/17 18:27:16	EST	-70.83584				
9								
10		Pre Event Avg (A)		60.00575	-1196.5	0	0	
11		Post 20-52 Avg (B)		59.959556	-1163.78	0	0	
12		Delta (Post - Pre)		-0.046194	32.72222	0	0	
13								-0.025
14	Row	DateTime	TZ	Frequency	NAI	Total Adjustments	Response Transfer	Delta Freq
15	1	12/06/17 18:26:12	EST	59.997	-1208	0	0	0
16	2	12/06/17 18:26:16	EST	59.998	-1207	0	0	0.001
17	3	12/06/17 18:26:20	EST	59.998	-1204	0	0	0
18	4	12/06/17 18:26:24	EST	59.998	-1199	0	0	0
19	5	12/06/17 18:26:28	EST	59.999	-1199	0	0	0.001
20	6	12/06/17 18:26:32	EST	60	-1198	0	0	0.001
21	7	12/06/17 18:26:36	EST	60.001	-1198	0	0	0.001
22	8	12/06/17 18:26:40	EST	60.003	-1197	0	0	0.002
23	9	12/06/17 18:26:44	EST	60.003	-1197	0	0	0
24	10	12/06/17 18:26:48	EST	59.999	-1198	0	0	-0.004
25	11	12/06/17 18:26:52	EST	59.997	-1199	0	0	-0.002
26	12	12/06/17 18:26:56	EST	60	-1199	0	0	0.003
27	13	12/06/17 18:27:00	EST	60.003	-1197	0	0	0.003
28	14	12/06/17 18:27:04	EST	60.007	-1190	0	0	0.004
29	15	12/06/17 18:27:08	EST	60.007	-1200	0	0	0
30	16	12/06/17 18:27:12	EST	60.006	-1199	0	0	-0.001
31	17	12/06/17 18:27:16	EST	60.005	-1202	0	0	-0.001
32	18	12/06/17 18:27:20	EST	59.98	-1224	0	0	-0.025
33	19	12/06/17 18:27:24	EST	59.966	-1261	0	0	-0.014
34	20	12/06/17 18:27:28	EST	59.961	-1237	0	0	-0.005
35	21	12/06/17 18:27:32	EST	59.958	-1141	0	0	-0.003

Data Collection / Submittal Simplification?



	A	B	C	D	E	F	G
1	Interconnection	EI					
2	BA Acronym	DUK					
3	Operating Year	2018					
4	Event	1					
5	Event Date (UTC)	12/05/17					
6	Event Time (UTC)	22:18:52					
7	Submitter Name	Tom Pruitt					
8	Submitter Email	tom.pruitt@duke-energy.com					
9	Submitter Phone	980-701-8117					
10	ScanHeader	DateTime	TZ	Frequency	NAI	Total Adjustments	Response Transfer
11	ScanData	12/05/17 17:17:52	EST	59.999	-693	0	0
12	ScanData	12/05/17 17:17:56	EST	59.996	-692	0	0
13	ScanData	12/05/17 17:18:00	EST	59.998	-689	0	0
14	ScanData	12/05/17 17:18:04	EST	60	-685	0	0
15	ScanData	12/05/17 17:18:08	EST	60.002	-687	0	0
16	ScanData	12/05/17 17:18:12	EST	60.003	-690	0	0
17	ScanData	12/05/17 17:18:16	EST	60.004	-693	0	0
18	ScanData	12/05/17 17:18:20	EST	60.003	-695	0	0
19	ScanData	12/05/17 17:18:24	EST	60.002	-698	0	0
20	ScanData	12/05/17 17:18:28	EST	60	-702	0	0
21	ScanData	12/05/17 17:18:32	EST	59.997	-707	0	0
22	ScanData	12/05/17 17:18:36	EST	59.996	-707	0	0
23	ScanData	12/05/17 17:18:40	EST	59.996	-706	0	0
24	ScanData	12/05/17 17:18:44	EST	59.995	-706	0	0
25	ScanData	12/05/17 17:18:48	EST	59.997	-706	0	0
26	ScanData	12/05/17 17:18:52	EST	59.997	-706	0	0
27	ScanData	12/05/17 17:18:56	EST	59.99	-705	0	0
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29	ScanData	12/05/17 17:19:04	EST	59.957	-762	0	0
30	ScanData	12/05/17 17:19:08	EST	59.954	-746	0	0
31	ScanData	12/05/17 17:19:12	EST	59.951	-740	0	0
32	ScanData	12/05/17 17:19:16	EST	59.95	-727	0	0
33	ScanData	12/05/17 17:19:20	EST	59.952	-698	0	0
34	ScanData	12/05/17 17:19:24	EST	59.953	-687	0	0
35	ScanData	12/05/17 17:19:28	EST	59.954	-687	0	0

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Existing Allocation and Alternate Methods

David Lemmons, Ethos Energy (Moderator); Bill Shultz, Southern Company; Sandip Sharma, ERCOT; and Danielle Croop, PJM

March 26, 2019

RELIABILITY | ACCOUNTABILITY




IFRO Allocation Panel

- David Lemmons
  - Overview of Current Process
- Sandip Sharma
  - TRE and ERCOT Process
- Danielle Croop and Bill Shultz
  - Allocation Options

Current Overview

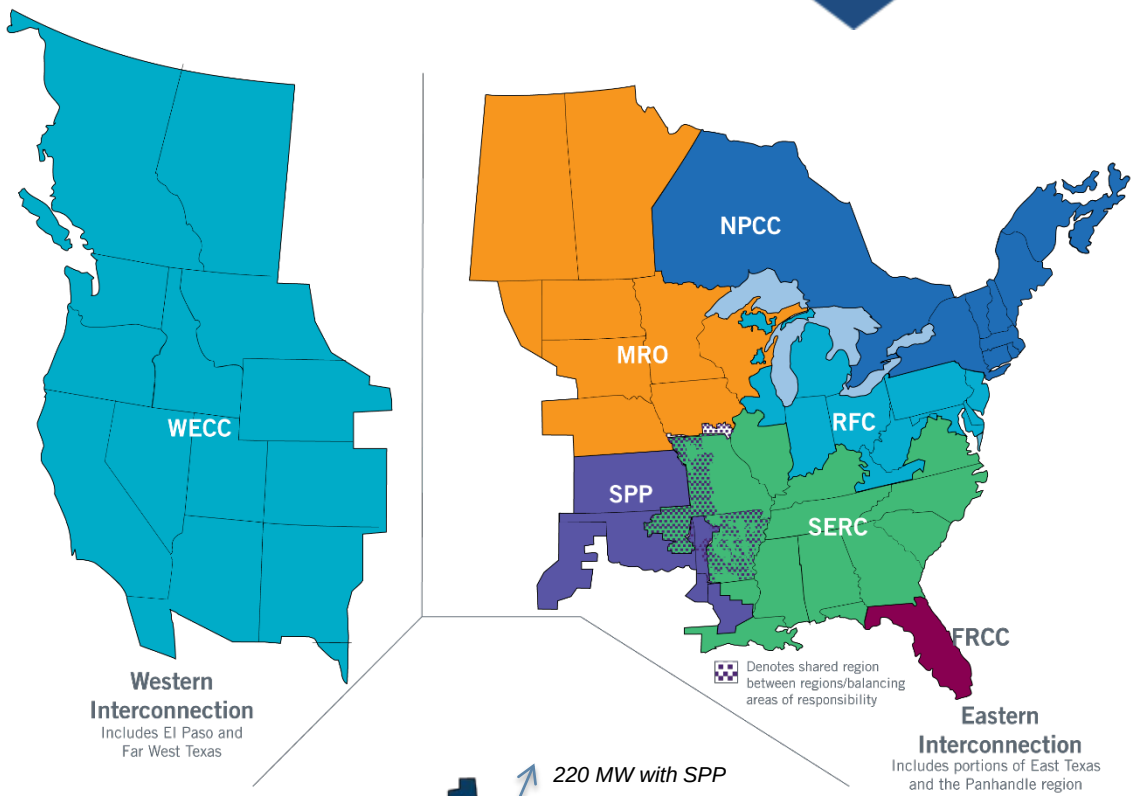
- Interconnection Frequency Response Obligation (IFRO) Allocation in Multi-Balancing Authority (BA) Interconnections
  - Current Process
    - Use FERC Form 714 Data to determine annual allocation to each BA
      - Majority of BAs have this data readily available
      - Non-jurisdictional entities provide this same information to NERC for this process
      - Data provided is MWh Load and Generation
    - BA allocation is then the BA's percentage of the Interconnection total
  - Pros
    - Numbers easily available
    - Addresses all BAs
  - Cons
    - Process Lag of two years
    - Somewhat burdensome administrative process
  - Some in industry have voiced concerns due to changes in resource mix

Sandip Sharma – TRE and ERCOT

The ERCOT Region

The interconnected electrical system serving most of Texas, with limited external connections

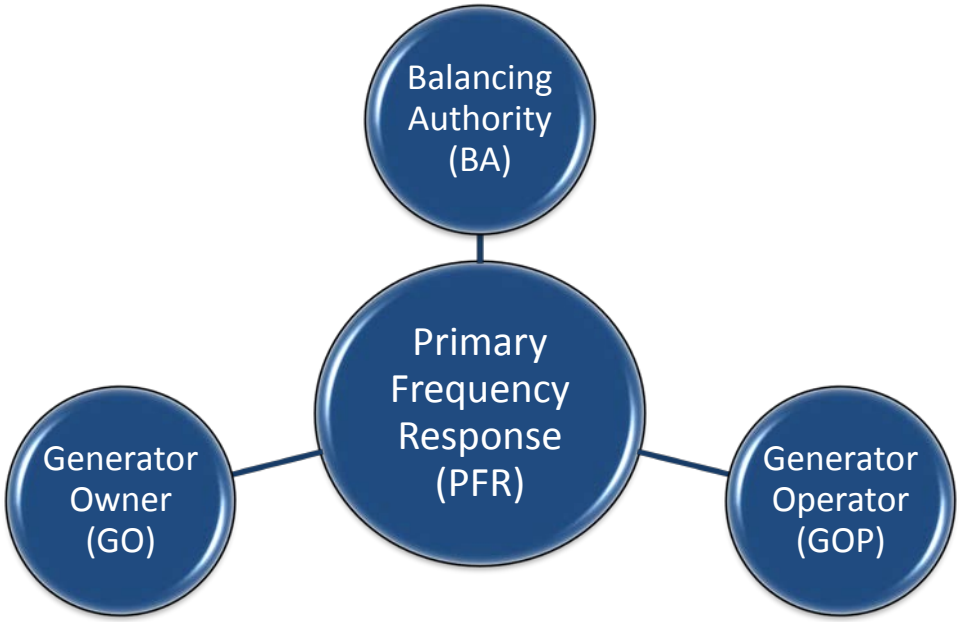
- 90% of Texas electric *load; 75% of Texas land*
- *73,259 MW peak, July 19,2018*
- More than 46,500 miles of transmission lines
- *570+ generation units*



ERCOT connections to other grids are limited to ~1250 MW of direct current (DC) ties, which allow control over flow of electricity

Overview of NERC Regional Standard BAL-TRE-001 (ERCOT)

- BAL-TRE-001 : Primary Frequency Response in the ERCOT Region
- Purpose: To maintain interconnection steady-state frequency within defined limits
- Functional Entities



Overview of NERC Regional Standard BAL-TRE-001

Balancing Authority (BA)

- R1 – Identify Frequency Measureable Events (FME)
- R2 – Measure PFR performance of each Generator
- R3 – Determine Interconnection Minimum Frequency Response (IMFR)
- R4 – Measure Interconnection's combined Frequency Response performance for a rolling average of the last six events
- R5 – Must take actions to improve frequency response if R4 measure falls below IMFR.

Generator Owner (GO)

- R6 – GO shall be responsible for Governor Droop and Dead-band setting of Generator as required in the standard
- R7 – GO responsible for ensuring Governor is in service and ***responsive to frequency*** when generating unit is online and released for dispatch. Responsible for notifying GOP if Governor cannot be in service.
- R9 – GO shall meet the Initial PFR performance metric (12-month rolling average initial Primary Frequency Response performance of 75% on each generating unit/generating facility, based on participation in at least eight FMEs)
- R10 – GO shall meet the sustained PFR performance metric

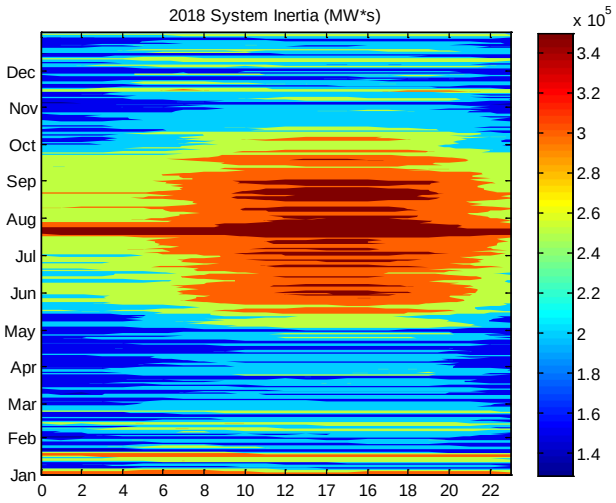
Generator Operator (GOP)

- R8 – GOP shall notify the BA as soon as practical but within 30 minutes of the discovery of a status change (in service, out of service) of a Governor

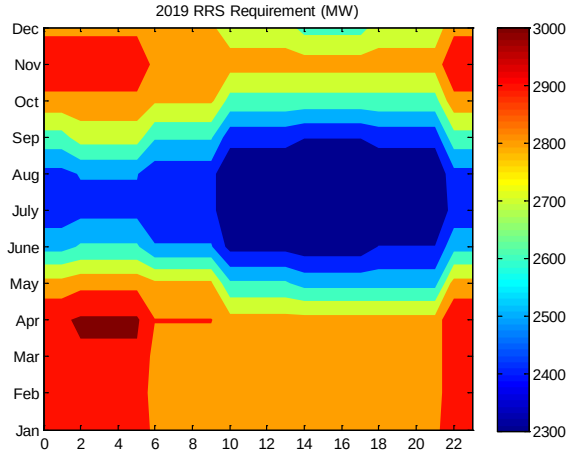
How Does ERCOT meet its IMFR / IFRO / FRO

- RRS is procured to ensure sufficient capacity is available to respond to frequency excursions during unit trips.
- To consistently meet BAL-003 Interconnection Frequency Response Obligation, ERCOT must plan not to activate UFLS for loss of 2750 MW of generation.
  - UFLS relays will shed firm load if frequency drops to 59.3 Hz (5% of total ERCOT load).
  - ERCOT plans to maintain frequency nadir at or above 59.4 Hz for loss of 2750 MW (0.1 Hz margin).

System Inertia 2018



Responsive Reserve Requirements 2019



RRS Table - 2018

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10	Scenario 11	Scenario 12
LR/PFR	2.25:1	2.11:1	1.99:1	1.87:1	1.77:1	1.69:1	1.61:1	1.54:1	1.47:1	1.41:1	1.36:1	1.3:1
Inertia (GW·s)	130	140	150	160	170	180	190	200	210	220	230	240
PFR Req. (no LR) (MW)	5246	4916	4620	4361	4132	3927	3743	3576	3424	3285	3157	3040
*RRS (MW)	3229	3162	3090	3039	2984	2920	2868	2815	2772	2726	2676	2643

	Scenario 13	Scenario 14	Scenario 15	Scenario 16	Scenario 17	Scenario 18	Scenario 19	Scenario 20	Scenario 21	Scenario 22	Scenario 23	Scenario 24	Scenario 25
LR/PFR	1.26:1	1.22:1	1.17:1	1.14:1	1.1:1	1.07:1	1.04:1	1.01:1	1.00:1	1.00:1	1.00:1	1.00:1	1.00:1
Inertia (GW·s)	250	260	270	280	290	300	310	320	330	340	350	360	370
PFR Req. (no LR) (MW)	2932	2831	2737	2650	2569	2492	2421	2353	2290	2230	2173	2119	2068
*RRS (MW)	2594	2550	2523	2477	2446	2408	2373	2342	2290	2230	2173	2119	2068

*RRS quantity is calculated with limit of 50% limit on LRs.

**Red font in table above identifies study scenario where RRS needed < 2300 MW. 2300 MW floor will be used in RRS requirement determination.

***Generation mix (CCs, Gas, SC, Coal, Steam) providing 1150 MW of PFR has been aligned with actual historic system operations.
Inertia < 250 GW·s: 30% Coal + 70% Rest. Inertia ≥ 250 GW·s: 15% Coal + 85% Rest

Danielle Croop and Bill Shultz

Challenges

- Challenges with current IFRO Allocation
  - Yearly allocation provides difficulties for large changes in BA footprint during an operating year
  - Gen-only and Load-only BAs could have difficulty meeting the allocation if a large number of events are selected where their gen/load is offline

- Allocation is currently on the BA to provide frequency response in the stabilizing period (20-52 seconds) of the event
  - Do reliability needs dictate separate requirements in the Arresting, Stabilizing and/or Recovering periods?
  - Do we need a real-time/individual event FR requirement?

Allocation Options

- BA Allocation
  - Static or real-time analysis?
  - Static analysis allocated on BA peak load or another method
    - Yearly allocation would still be applied
  - Real-time analysis
    - Would provide additional complexity

Frequency of FRO Recalculation

- Frequency of Frequency Response Obligation(FRO) calculation options – adjustments to match BA changes
  - Yearly – perhaps frequent enough
  - Quarterly/Monthly
  - In real time – per event
    - Requires additional infrastructure to monitor and deliver obligation info
    - Not currently in place – cost to achieve this is high initially + must be maintained
    - Operational planning facet – the planning target continuously moves – hard to hit a moving target
    - Interconnection comparisons
      - EI – no single entity overviews the interconnect
      - WI – Peak RC could have done it – moving to several RC's
      - NERC Emergency Operations Center or EIDSN - see complete interconnections
- FRM must be equal to or more often than Interconnection Frequency Response Obligation (IFRO) allocation

Other Entities

- Adding a GO or GOP Allocation
  - Capability or Performance requirement?
  - Capability
    - Require verified droop and deadband requirements on resources
    - Address Outer loop controls and squelching response from resources
    - Similar requirements to FERC Order 842
  - Performance requirement
    - Would need to be coordinated with other rules
- Any GO/GOP requirement would not remove requirement of the BAs.
  - It could cause the BA requirement to change from what exists today

GO FRO Allocation Issues

- Allocation of FRO to the GO may be problematic
  - Measurement capability
    - Current gen monitoring to EMS 2-4 sec, 6 sec, 1 sec best to evaluate C space performance
    - ICCP data not that fast and is not UTC time sync'd
    - Texas example – GO data flow: GO→QSE→TOP→ERCOT
  - GO/GOP does not determine what units are running at any given time
- This does not mean all requirements are unreasonable, such as
  - Droop and deadband settings
  - Controls
  - Provide specific information
  - Addressing BA concerns with performance

Controllable Elements of Frequency Response Variation

- Can plan for some MW loss – probably likely worst case (single contingency) - RLPC
- Dispatch mix of generation
  - system inertia targets,
  - FRR,
  - FR active
- FR ability of generation achievable through many mechanisms…
  - OEM Equipment Specifications
  - Frequency Response Initiative
  - Interconnection Agreement (FERC Order 842)
  - Markets
  - regional requirements
  - national regulations
- FR contribution of loads
- Establishment of FRR markets

Possible FRO Allocation

- Net Energy for Load
  - This method may be lowest administrative burden
  - NERC funding is based on Net Energy for Load
  - Gen only BAs – low or no allocation?
  - High load or load only BAs – high allocation?

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Panel 4: Applicable NERC Registered Entities

Linda Lynch, NextEra Energy (Moderator); Jim Fletcher, AEP; Sandip Sharma, ERCOT; and Terry Bilke, MISO

March 26, 2019

RELIABILITY | ACCOUNTABILITY




Agenda

- Considerations for BAL-003 Standard Requirements
- Contributions of Grid Participants
- Limitations of Interconnection Agreements
- Interconnection Differences
- Capabilities
- Questions and Answers

Considerations for the BAL-003 Standard Requirements

Considerations

Should there be a Frequency Responsive Reserve Requirement?

- The Standard Authorization Request (SAR) for this project does not ask for the development of a commodity requirement
- The drafting team does see value in developing an approach to estimate frequency responsive reserves and make this data available
- There are ways to accomplish this using tools other than requirements

Considerations

Is interchange the appropriate parameter to measure?

- Measuring the change in net actual interchange for a frequency disturbance is the traditional way to measure frequency response at the Balancing Authority (BA) level. While in theory individual generators could be measured, as noted later, it is not a practical solution at this point
- The drafting team has identified one case where a modified measure is appropriate. There are a few BAs who experience significant increase in losses on their system when a remote generator trips in a particular direction. The drafting team believes this can be appropriately addressed via the adjustments process in the Frequency Response Survey forms

Considerations

- BAs that experience and can measure the change in losses can add them to their adjustment with the caveat that the loss adjustment be used for all events, not just those that negatively impact their Frequency Response Measure

Losses Example

- In analyzing a single BA performance with 3 years of BAL-003 event data, Compliance could be predicted based upon location of resource loss relative to the majority of Frequency Responsive Resources within the Western Interconnection

Location of Resource loss and RESULTS	PREDICTABILITY	PREDICTED OUTCOME
Desert Southwest 9 OUT OF 15	60%	Coin Flip
Western US 15 OUT OF 19	79%	PASS
Colorado/Utah 18 OUT OF 22	**82%**	**FAIL**
Internal to the BA 13 OUT OF 13	100%	PASS

Loss Adjustment

Considerations

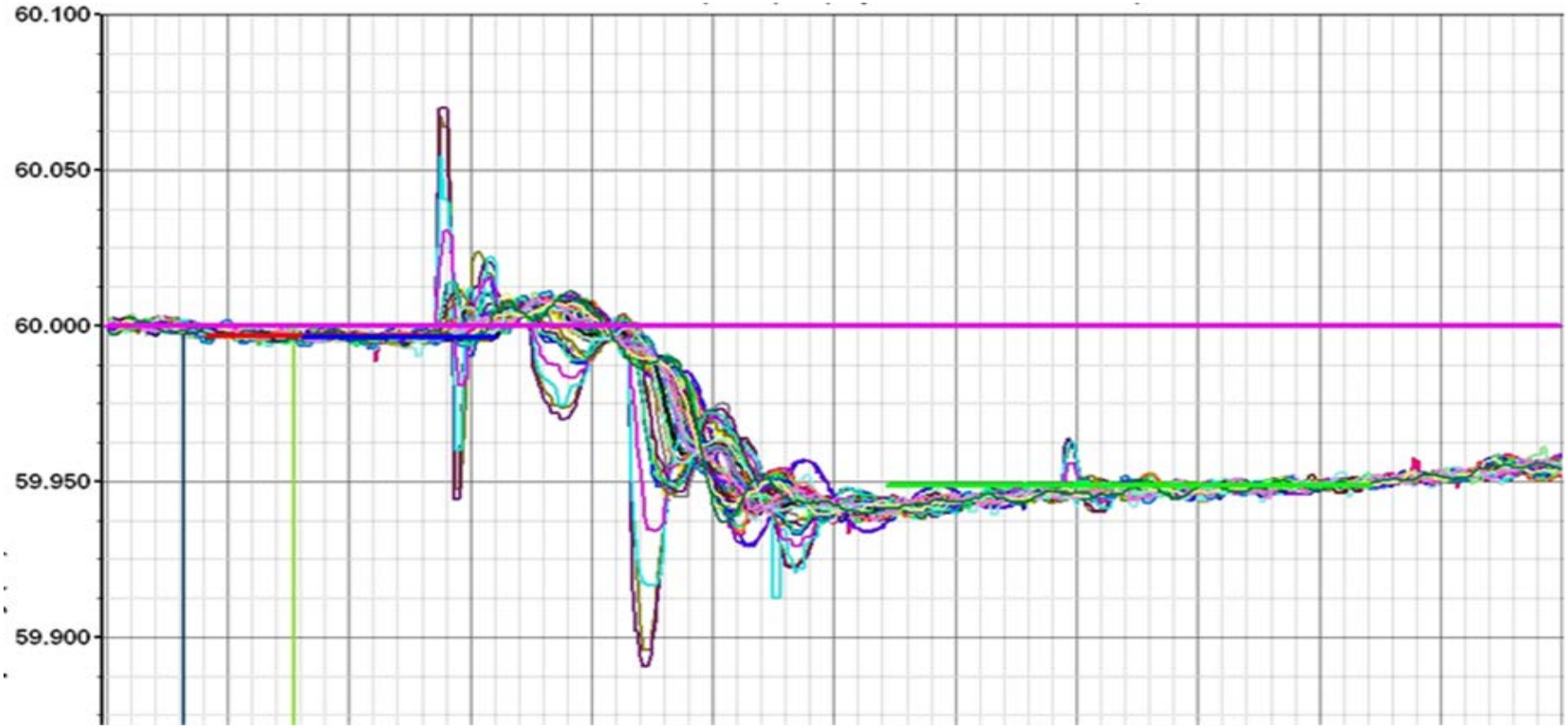
Should we measure Frequency Response at point C rather than at the B value?

- While conceptually you could measure performance at the generator level using synchrophasors, the level of complexity outweighs the perceived benefits. First, frequency is not the same through an interconnection, nor does C occur at the same time as seen in the event below …

see next slide …

Considerations

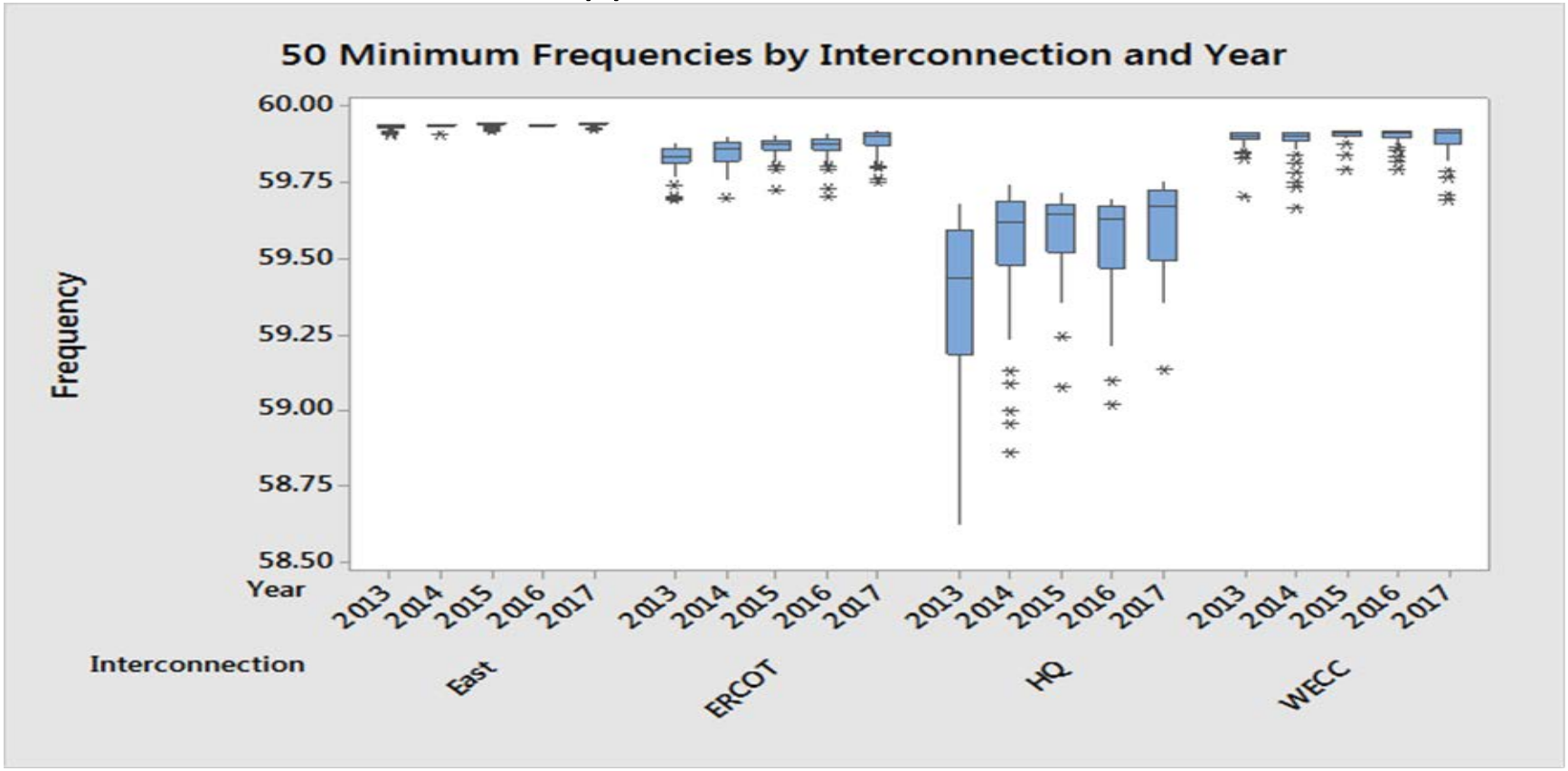
- Additionally, point C is not just a function of frequency response, but also Interconnection inertia. You cannot directly manage the depth of point C with governors during periods of lower inertia.



(source University of Tennessee-Knoxville (UTK) FNet)

Considerations

- Finally, data from UTK shows that the minimum frequencies we observe have not been declining and are well above Underfrequency Load Shedding. There does not appear to be a need to change the current measurement approach



Considerations

Should the Frequency Response Obligation be allocated in real time?

- If each event were evaluated separately for compliance, it would be appropriate to develop a minute-to-minute obligation based on load and/or generation, particularly if the Interconnections were at risk at particular load levels
- The balancing standards are by design risk and performance based and utilize the benefits associated with interconnected operations. As the bias and Frequency Reserve Obligations (FRO) are evaluated annually, and there is sufficient frequency response in each Interconnection, there is no apparent reliability benefit moving to constantly changing the Interconnection Frequency Response Obligation (IFRO) allocation

Considerations

- While there are alternative ways to allocate IFRO (e.g. NERC Net Energy for Load rather than FERC 714 data), no approach will be perfect.
- While there is no need for change in allocation at this time, the standard drafting team (SDT) sees some benefit in promoting an approach to estimate Frequency Responsive Reserve.

Contributions of Grid Participants

Grid Participants

- Synchronous Generators, Wind, Solar, Storage, demand response, etc.
- NERC recommends that all generating resources be equipped with a functioning governor
  - Droop Setting
  - Governor Dead-band
- FERC Order 842 requires new synchronous and non-synchronous generators, to install, maintain, and operate equipment capable of providing PFR as a condition of interconnection.
- Headroom is prerequisite for providing Primary Frequency Response

Limitations of Interconnection Agreements

Interconnection Agreements

- Prior to FERC Order No. 842, no firm requirements in Generator Interconnection Agreements (GIA)
- Old GIA Summary
  - Generators will have governors, except when they don't
  - The governors will be in operation, except when they're not
- New GIA Summary (FERC Order No. 842)
  - Generators need functioning governors set to NERC Guidelines
  - Generators need to notify Transmission Provider when governor is taken out of service
  - No obligation to maintain headroom

Interconnection Agreements

- **ISO/RTO Risk Transfer**
  - The majority of generators are within the footprint of an ISO/RTO with provisions in their tariffs, such that if an entity within their footprint causes the RTO to be non-compliant, sanctions can be passed along to the deficient entity.
- **BA Operating Instructions to GOP**
  - Non-RTO tariffs generally include a regulation and frequency response ancillary service. If a BA is not obtaining frequency response from its generators and the BA's performance is trending toward non-compliance, the BA could issue an Operating Instruction to its generators to place their governors in a responsive mode. While a generator can reply that it is unable to follow the Operating Instruction, the BA may have tariff provisions it can enforce.

Interconnection Agreements

- **NERC Requirements for Real-time Data**
  - IRO-010-2 and TOP-003-3 allow BAs, RCs, and TOPs to request real-time data from generators. Governor status and currently available headroom could be requested from generators to enable an estimate of frequency responsive reserves
- **Sensitivity to Low Inertia or Light Load**
  - If studies show that a BA has some risk during low-inertia, light load conditions, the BA can re-dispatch such that responsive generators have headroom as well as issue Operating Instructions for generators to be placed in a frequency-responsive mode. Again, some generators may not be capable of doing so, but they are obliged to notify the BA why they cannot respond

Generator Frequency Response Performance Requirement

- If Frequency Response is stable or improving, no action required
- If not,
  - GIAs require new resources to have frequency response capability
  - BAs can require frequency response to be enabled and to notify BA if not capable
  - BAs can also request status of currently available headroom
  - BAs may be able to re-dispatch resources to create headroom, but also may need to pay resource lost opportunity costs

Interconnection Differences

Interconnection Differences

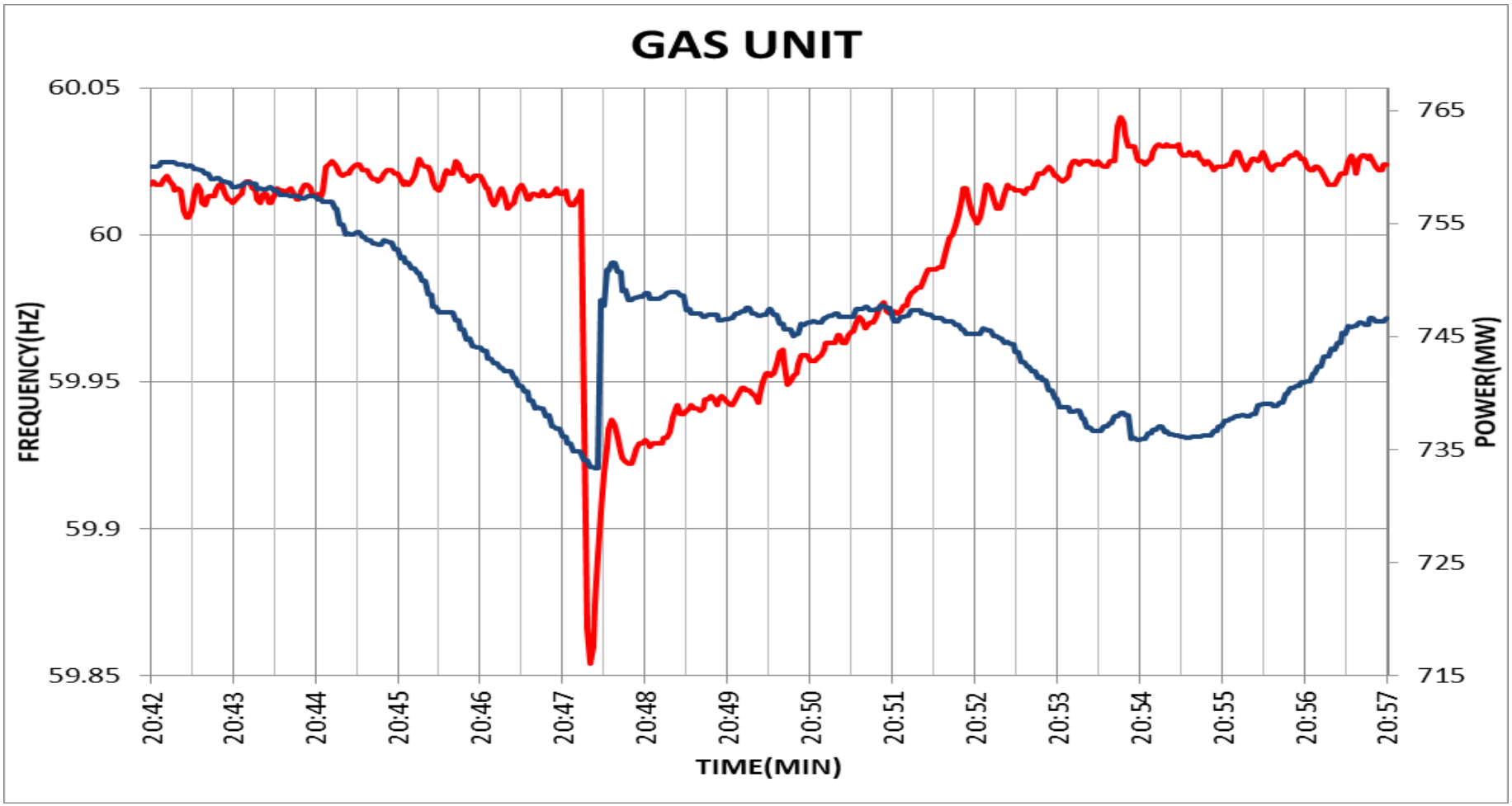
- Do all Interconnections need the same Frequency Response?
- How does load response, system inertia, and fast frequency response impact the need for Primary Frequency Response (PFR)?
- Why are UFLS settings different?
- Two interconnections have mandatory governor settings requirements today. Are the reliability benefits worth the additional cost?
- All four interconnections have similar RLPCs ranging from 2000 MW in HQ to 3209 MW in Eastern Interconnect, while the inertias vary greatly. Does the total number of generation loss events in an interconnection indicate a reliability need for PFR?

Interconnection Differences

- What factors should be considered, transmission system topology, geographic distribution of generation, and load of an interconnection, to list a few?
- How does the increasing penetration of intermittent inverter-based generating resources, or inverter-based storage resources in a given interconnection impact the need for firm capacity and PFR?
- The number of BAs registered in the interconnections varies from one (1) in HQ and ERCOT, to 34 and 39 in Eastern and Western Interconnections, respectively. How does the number of BAs in an interconnection impact reliability?

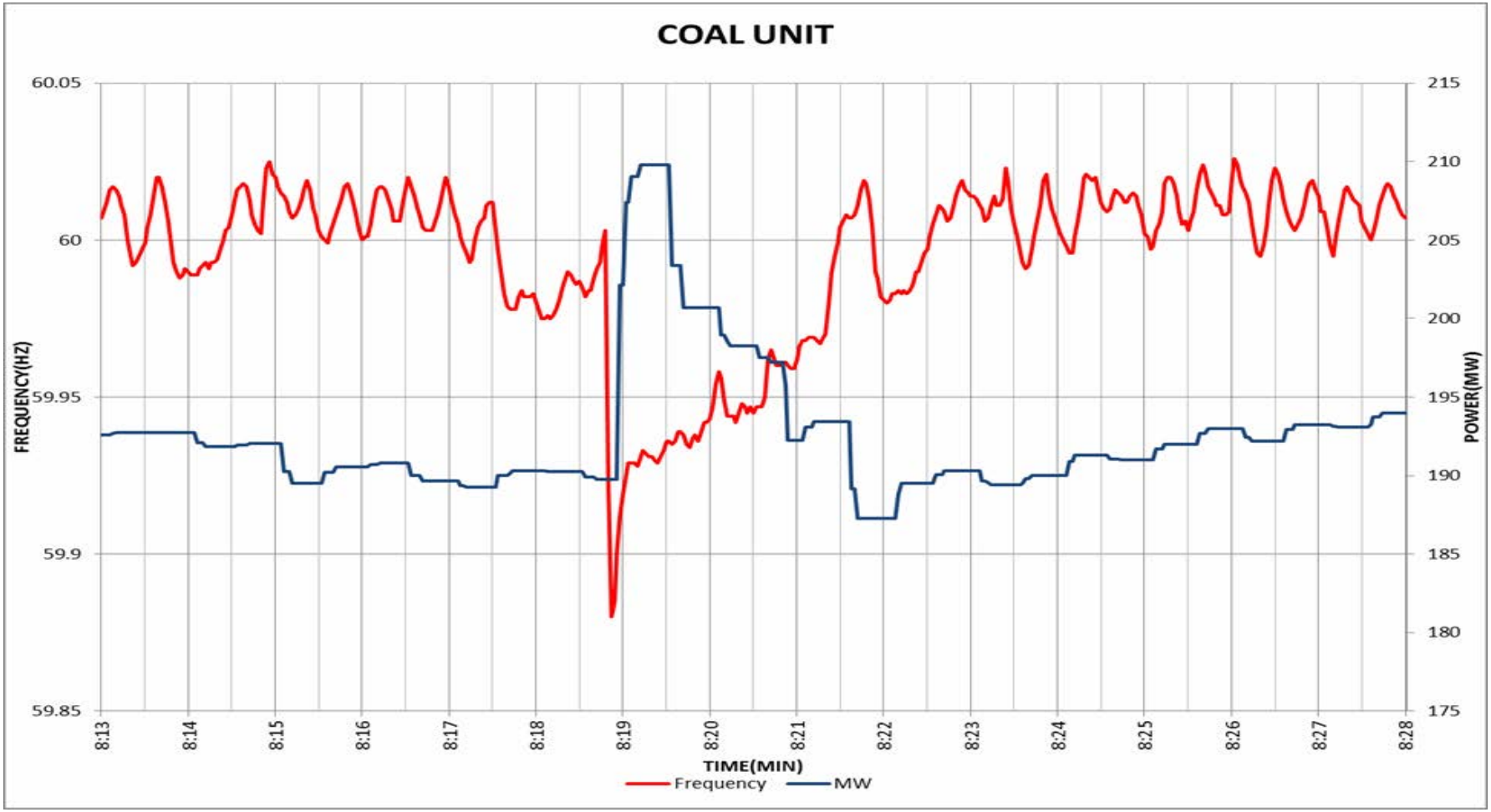
Response to Frequency Events by Generation Type

Gas Unit Responding to Frequency Event



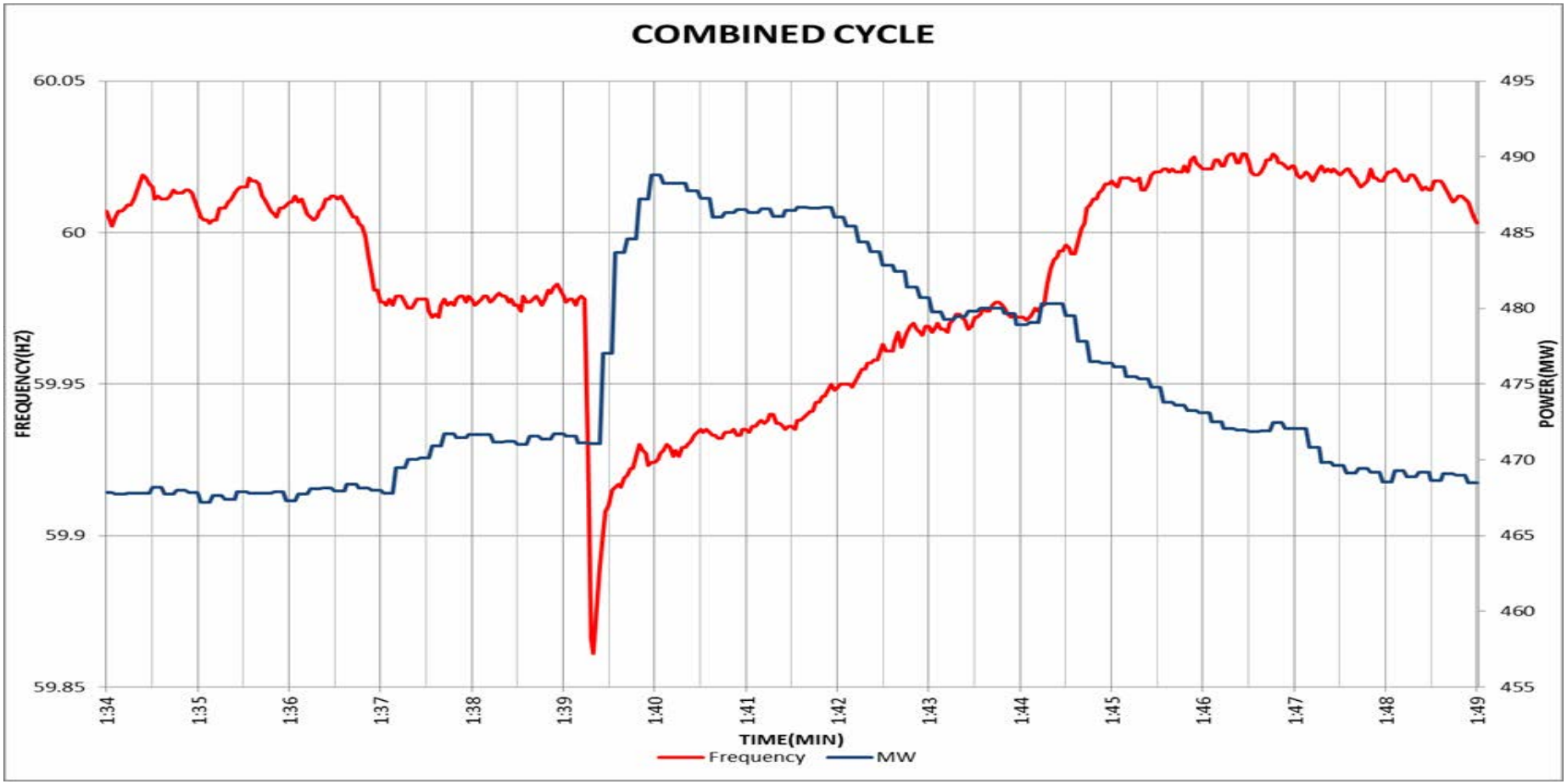
Gas Unit Responding to Low Frequency Event at 17 mHz Deadband and 5% Droop

Coal Unit Responding to Frequency Event



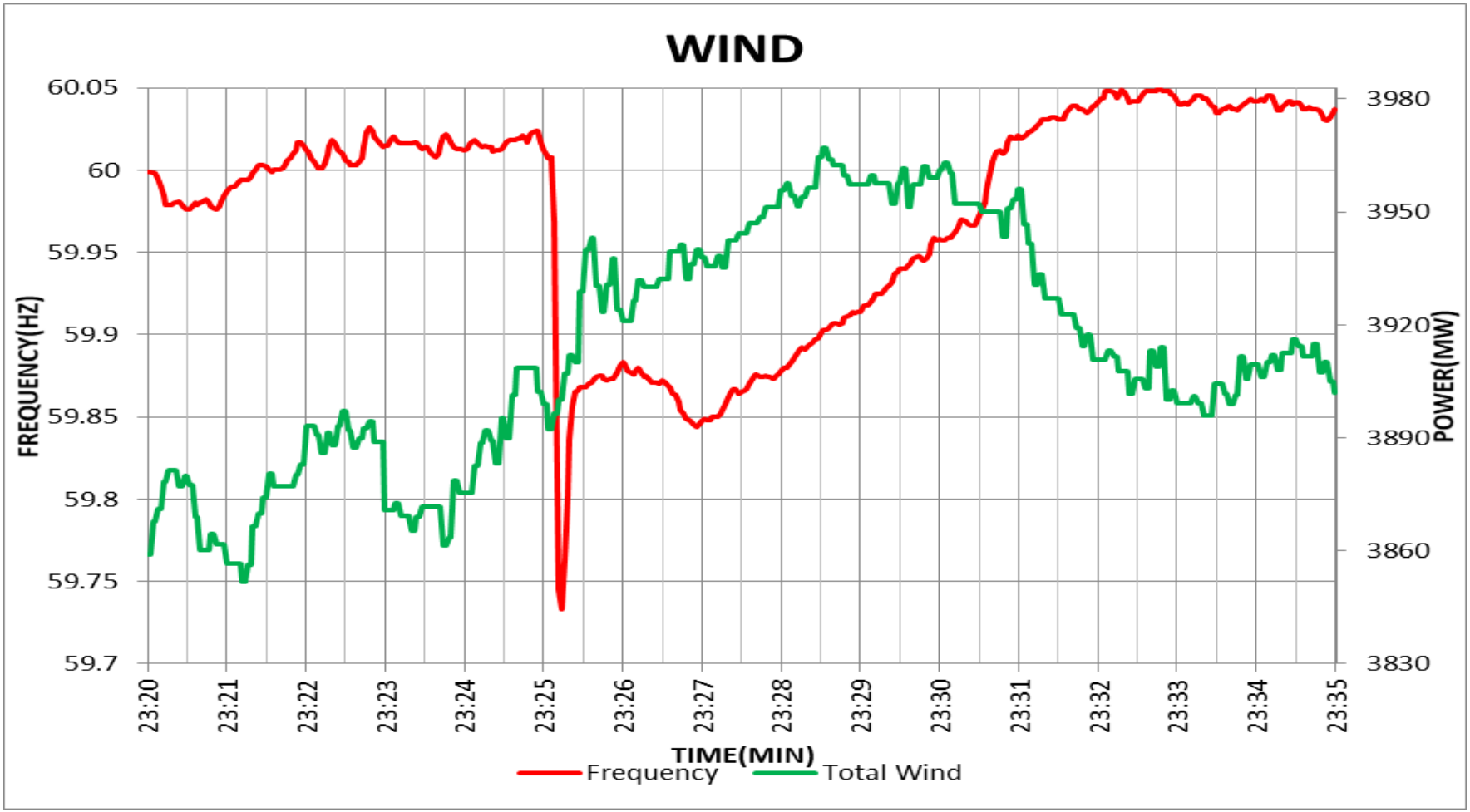
Coal Unit Responding to Low Frequency Event at 17 mHz Deadband and 5% Droop

Combined Cycle Unit Responding to Frequency Event



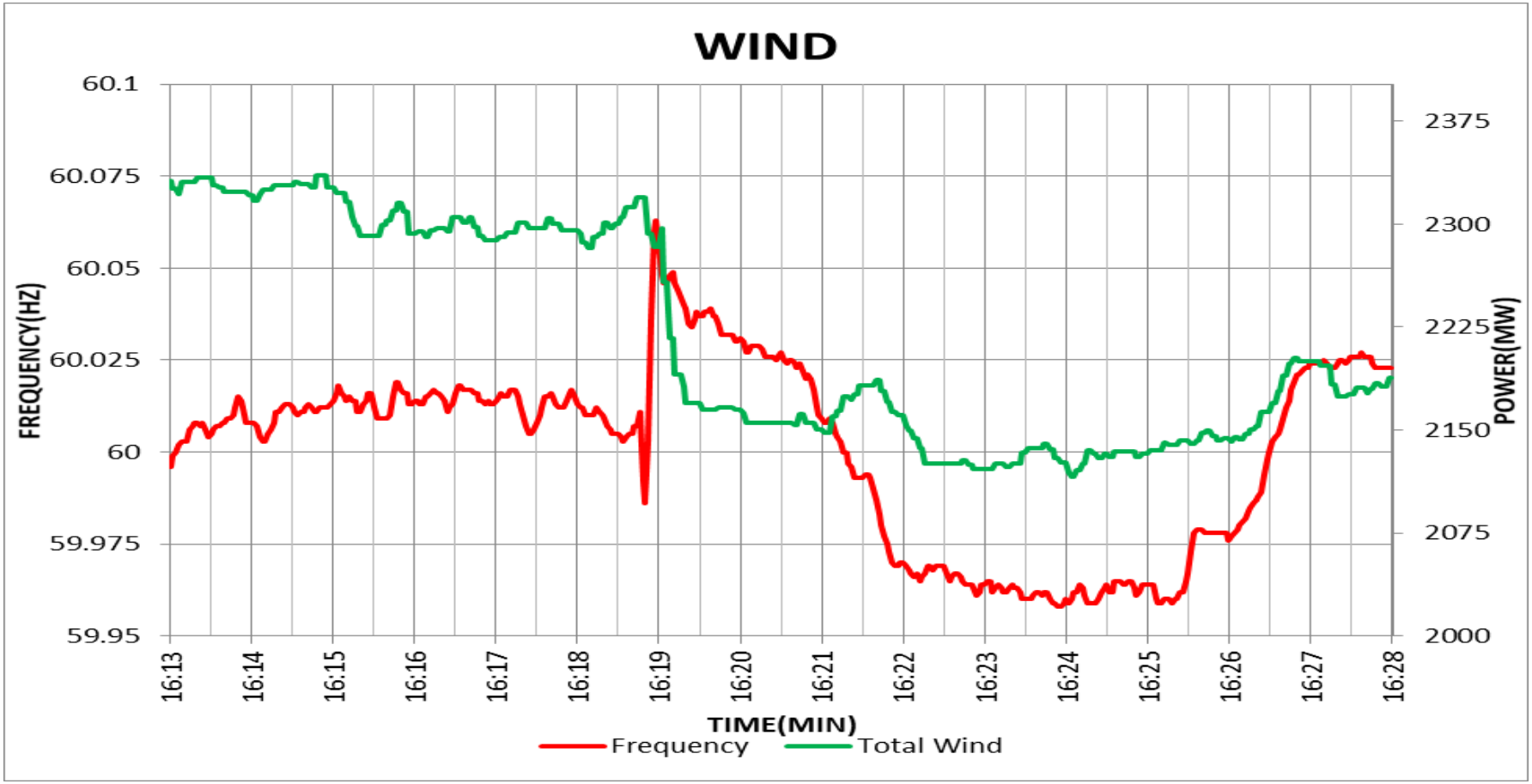
Combined Cycle Unit/Block Responding to Low Frequency Event at 17 mHz Deadband in ERCOT

Wind Unit Responding to Low Frequency Event



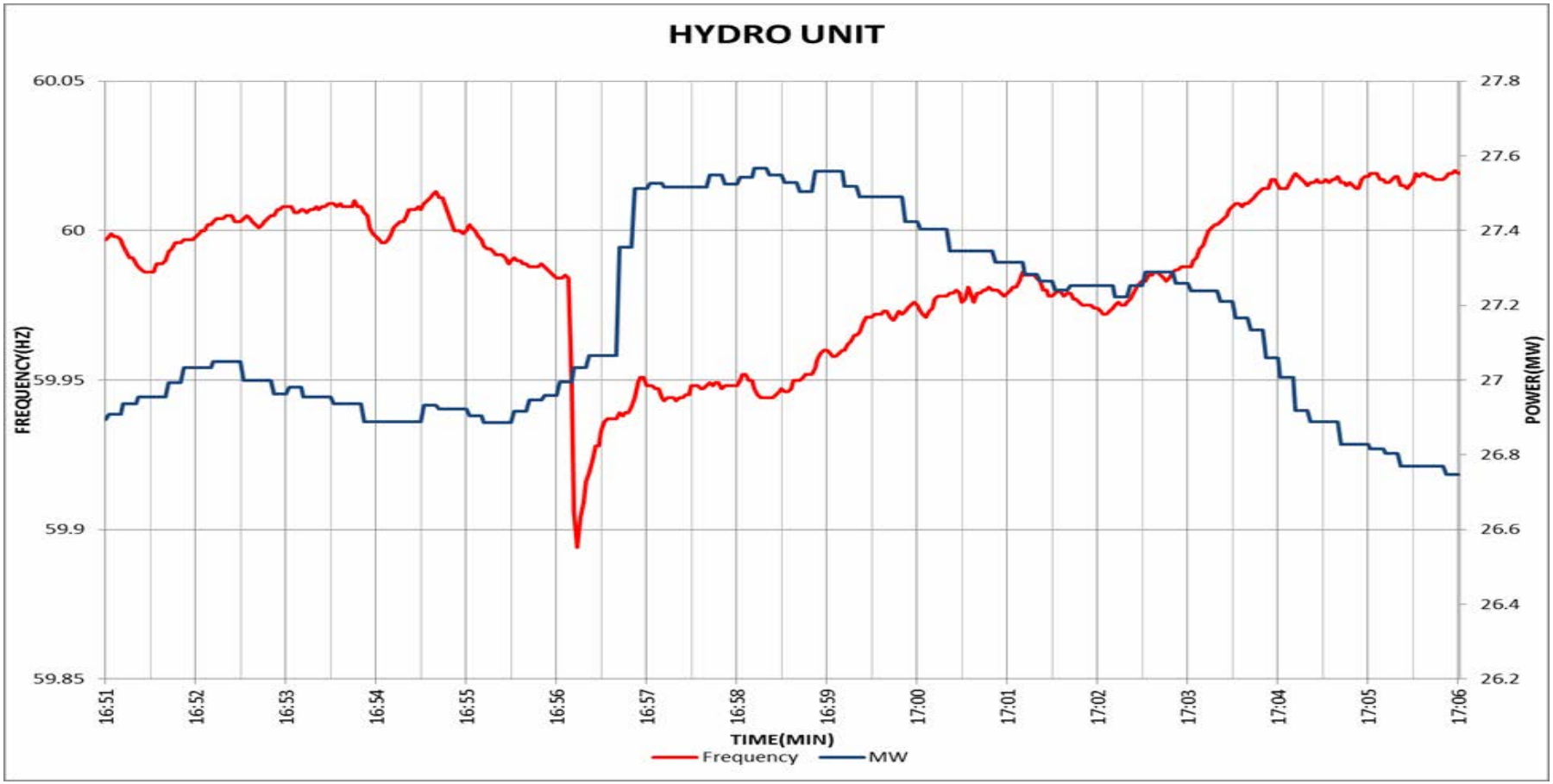
Wind Resources Responding to Low Frequency Event at 17 mHz Deadband and 5% Droop

Wind Unit Responding to High Frequency Event



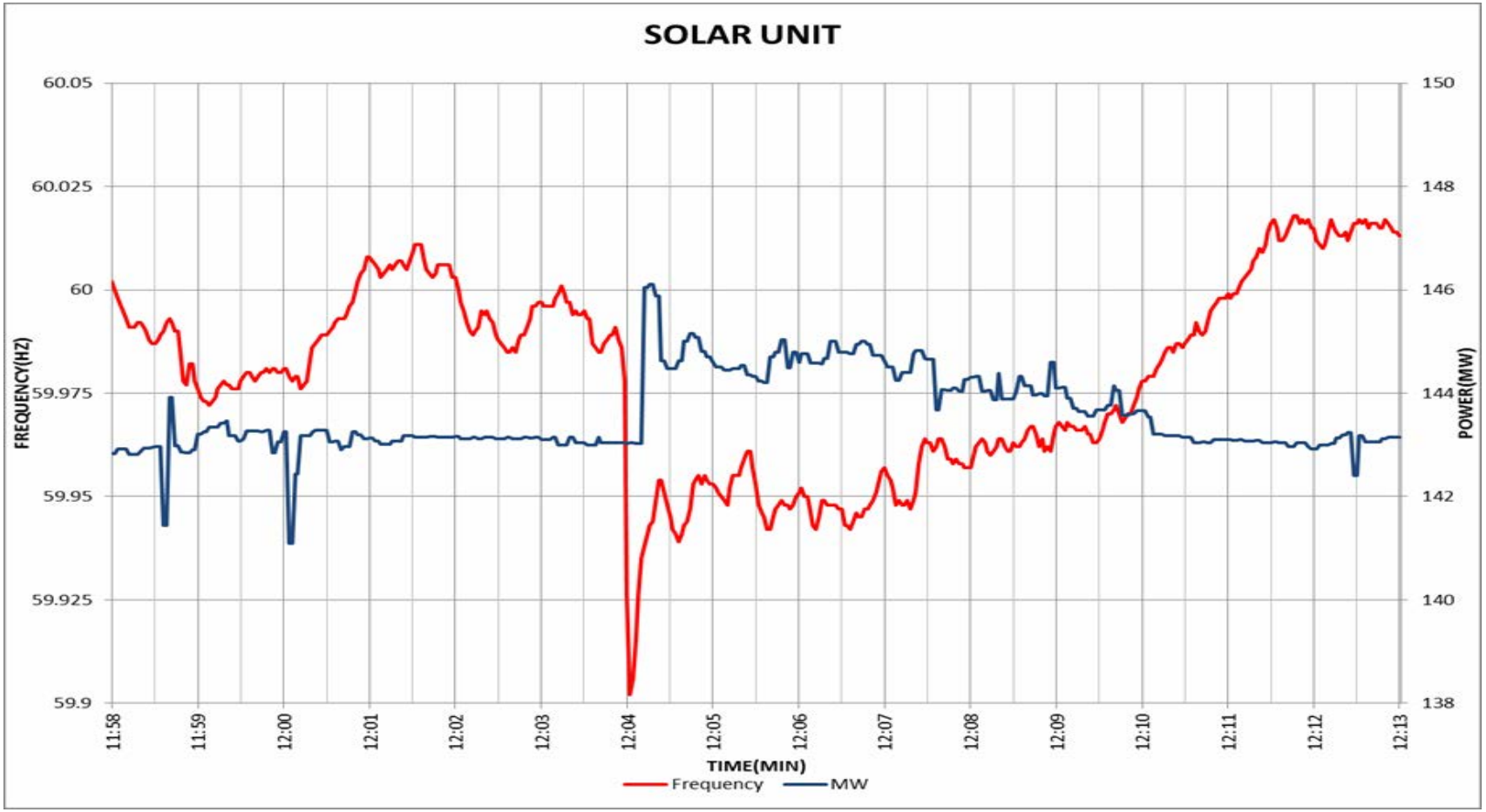
Wind Resources Responding to High Frequency Event at 17 mHz Deadband and 5% Droop

Hydro Unit Responding to Low Frequency Event



Hydro Resource Responding to Low Frequency Event at 17 mHz Deadband and 5% Droop

Solar Unit Responding to Low Frequency Event



Solar Resource Responding to Low Frequency Event at 17 mHz Deadband and 5% Droop in ERCOT

Questions and Answers