Forward Looking Frequency Trends Technical Brief

ERS Framework[1] Measures 1, 2, and 4: Forward Looking Frequency Analysis

The NERC Planning Committee and Operating Committee jointly created the Essential Reliability Services Task Force (ERSTF) in 2014 to consider reliability issues that may result from the changing generation resource mix. In 2015, the ERSTF proposed measures for essential reliability services (ERSs) for examination and potential ongoing monitoring to identify trends. The ERSTF was converted into the Essential Reliability Services Working Group (ERSWG) in 2016 and charged with identifying, evaluating, and developing sufficiency guidelines for each quantifiable measure.

The ERSWG frequency measures are intended to monitor and identify trends in frequency response performance as the generation mix continues to change. The holistic frequency measure, called Measure 4 in ERSWG reports, tracks phases of frequency performance for actual disturbance events in each Interconnection (e.g., initial frequency rate of change, and timing of the arresting and recovery phases). Other measures look at components of this coordinated frequency response, such as the amount of synchronous inertial response (SIR, Measure 1) and the initial rate of change in frequency following the largest contingency event (RoCoF, Measure 2). This paper describes the analysis by using forward-looking projections that will be performed as part of the NERC reliability assessment process.

Background

Frequency support is the response of generators and loads to maintain the system frequency in the event of a system disturbance. Frequency support is provided through the combined interactions of synchronous inertia (traditionally from generators such as natural gas, coal, and nuclear plants as well as from motors at customer locations) and frequency response (from a wide variety of generators and loads). Working in a coordinated way, these characteristics arrest and eventually stabilize frequency. A critical issue is to stabilize the frequency before it falls below underfrequency load shedding values or rises above overfrequency relay trip settings.

It is important to understand that inertia and frequency response are properties of the Interconnection (not to each balancing area individually) and these properties have different characteristics for each Interconnection. For example, if changes to the resource mix alter the relative amounts of synchronous inertial response or frequency response, various mitigation actions are possible (such as obtaining faster primary frequency response from other generators or loads) to maintain or improve overall frequency support.

[1] Essential Reliability Services Working Group, Measures Framework Report, November 2015

Trends in the frequency measures can be analyzed using historical data and projected into the future using reasonable planning assumptions and models. This document discusses each frequency measure and describes the analysis that will be performed as part of the NERC reliability assessment process and included in the NERC Long Term Reliability Assessment (LTRA) report. The NERC Resources Subcommittee (RS) will be monitoring the historical trends and annually reporting results in the NERC State of Reliability (SOR) report that was discussed in a separate Technical Brief.

Interconnection Approaches to Future-Looking Frequency Support Measures 1, 2, and 4

As noted above, frequency response and synchronous inertia are properties that are unique to each Interconnection. Projecting the future frequency support characteristics requires modeling of the future state of the Interconnection when using reasonable assumptions and scenarios. The following sections discuss the efforts and plans for each Interconnection.

To provide a starting point for the discussion, **Table 1** shows the history of minimum inertia records in each Interconnection between 2013 and June 2017. Minimum inertia is of interest because the initial frequency decline following large generation trip events is the fastest during low inertia conditions.

Table 1: Lowest Inertia (H) by Interconnection 2013–June 2017 (GVA*s)						
Interconnection	**Year**	**2013**	**2014**	**2015**	**2016[2]**	**2017[3]**
ERCOT	**Date and Time**	March 10 3:00 a.m.	March 30 3:00 a.m.	November 15 2:00 a.m.	April 16 2:00 a.m.	February 17 2:00:00 a.m.
	Minimum Synchronous H (GVA*s)	132	135	152	143	134
	System Load at Minimum Synchronous H (MW)	24,726	24,540	27,190	27,831	29,515
	Percent of Non-synchronous Generation[4]	31	34	42	47	42
Québec (PPPC[5] Limit)	**Date and Time**	September 16 4:00 a.m.	October 5 2:00 a.m.	August 2 4:00 a.m.	July 3 4:00 a.m.	May 26 4:00 a.m.
	Minimum PPPC Limit (MW)	980	860	920	870	920
	System Load at Minimum PPPC Limit (MW)	14,910	14,550	14,350	15,650	15,090
	Percent of Non-synchronous Generation	6	2	6	14	12
Québec (Inertia)	**Date and Time**				October 8 3:30 a.m.	May 26 4:30 a.m.
	Minimum Synchronous H (GVA*s)				59.09	63.46
	System Load at Minimum Synchronous H (MW)				13,550	14,710
	Percent of Non-synchronous Generation				13	12
Eastern	**Date and Time**				October 22 9:11 a.m.	April 24 1:58 a.m.
	Minimum Synchronous H (GVA*s)				1,279	1,281
	System Load at Minimum Synchronous H (MW)				236,513	218,787
	Percent of Non-synchronous Generation				N/A	N/A
Western	**Date and Time**				October 16 11:45 a.m.	Apriil 9 7:19 a.m.
	Minimum Synchronous H (GVA*s)				498	472
	System Load at Minimum Synchronous H (MW)				76,821	86,183
	Percent of Non-synchronous Generation				10	12

[2] Inertia data for all Interconnections (except ERCOT) begins in June 2016.
[3] 2017 Minimum synchronous inertia (H) is only based on January to June data.
[4] Percent of Non-Synchronous Generation is reported as a percent of the system load
[5] The term PPPC is an acronym in French: P = Perte = Loss, P = Production = (of) Generation, P = en Première = First (meaning "following a Single"), C = Contingence = Contingency. PPPC limit is defined as the maximum amount of generation that can be lost in single contingency without reaching Under Frequency Load Shedding (UFLS) values. This will be discussed in details further in the paper.

ERCOT and Hydro Québec

Compared to the Western and Eastern Interconnections, Hydro Québec (HQ) and ERCOT are relatively smaller in area size and in the number of customers they serve. Both HQ and ERCOT are Interconnections that consist of a single balancing area.

In ERCOT, approximately 20 percent of the installed generation capacity is from wind resources (as of the end of 2016), and there are times when wind generation is serving up to 50 percent of ERCOT's total system load. In HQ, the majority of the generation capacity comes from hydro resources that, in general, have lower inertia in comparison to coal and combined-cycle units of the same MW size.

Consequently, these two Interconnections are actively addressing issues with lower system inertia and faster frequency decline after large contingencies.

HQ and ERCOT have put in place the following requirements and practices to ensure sufficient frequency performance in compliance with NERC BAL-003-1.1[6] standard:

- ERCOT and HQ require primary frequency response (PFR) capability enabled on all on-line generators that are over 10 MW in size and connected at the transmission level. The generators are expected to respond with a specified droop value (normally four to five percent) when system frequency is outside of a predefined deadband (±17 mHz in ERCOT, no deadband in HQ).
- Additionally, ERCOT and HQ also procure reserves[7] for primary frequency control (i.e., for frequency containment after a large generation loss).
- Up to a half of ERCOT's primary frequency reserve (called responsive reserve service) can be provided by load resources with underfrequency relays. [8] This fast response from load resources is considered to be fast frequency response (FFR).
- HQ has a "synthetic inertia[9]" requirement for wind turbines that is described in more detail in the Appendix A: Synthetic Inertia Requirements of Wind Power Plants in Hydro Québec.

Notably, the two Interconnections have chosen different mitigation strategies to ensure reliable operation during low system inertia conditions that are described below.

[6] NERC Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

[7] ERCOT procures reserve for Primary Frequency Control through the Ancillary Services market, while Hydro Quebec secures the reserve through bilateral contracts.

[8] Load Resources providing Responsive Reserve Service will trip at trigger frequencies that are higher than the involuntary UFLS trigger points. Participation in this paid for Ancillary Service is voluntary and should not be confused with Under Frequency Load Shedding.

[9] "Synthetic inertia" is a term sometimes used for fast controlled active power injection from wind generators in response to frequency decline after a large generation trip. This control is enabled by accessing stored kinetic energy (inertia) of the turbine, hence the term "synthetic inertia"; however, the response is not inherent and physics of the behavior is fundamentally different from inertial response of synchronous machines. The term "synthetic inertia" is used in HQ grid code to define the requirements and therefore is kept in this report.

ERCOT

Figure 1 shows boxplots of synchronous inertia levels for years 2013–2017 for ERCOT[10]. The corresponding lowest inertia for each year is shown in **Table 1**. The blue circles in the boxplot correspond to the system inertia when the highest portion of load was supplied by wind generation in a given year.

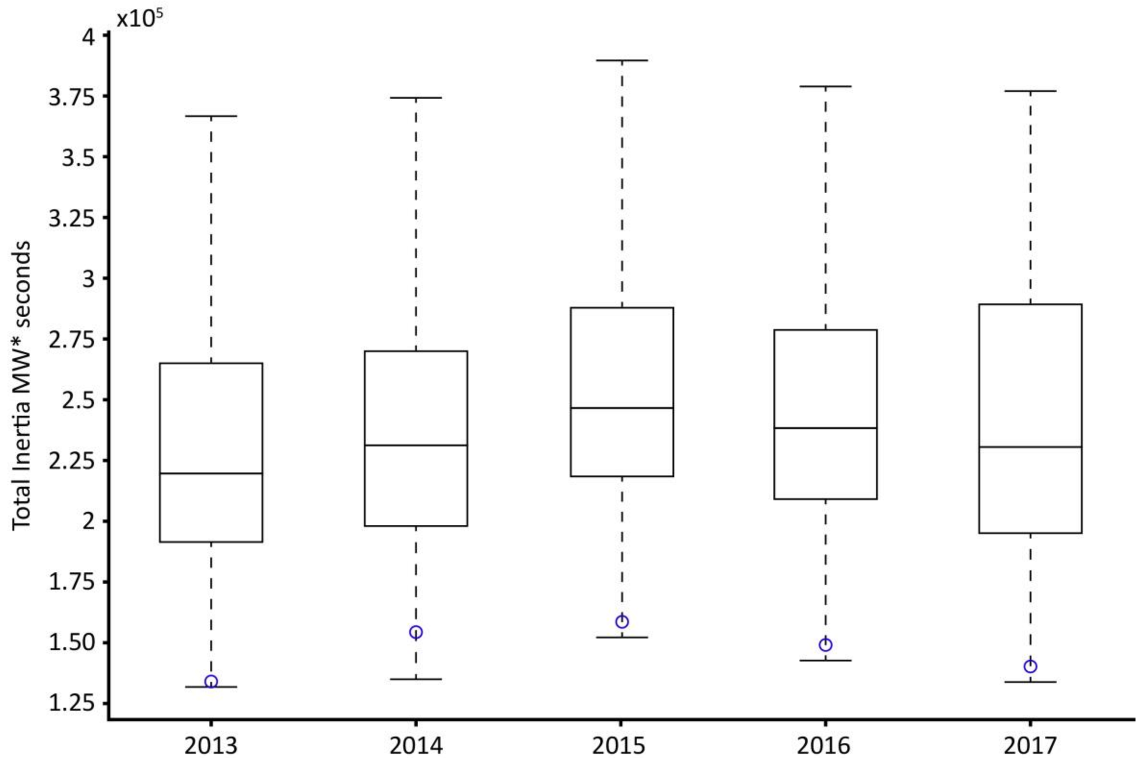

Figure 1: Boxplot[11] of ERCOT System Inertia 2013-2017

Figure 1 shows that both the median system inertia (indicated by the red line in each box plot) and the minimum inertia at ERCOT had an upward trend between years 2013 and 2015 even though the installed capacity of wind generation increased over same these years. **Figure 2** provides the yearly wind capacity additions (both installed and projected) between 2000 and 2020. Due to lower natural gas prices, coal fired generation is continuing to be replaced by combined-cycle generators in the unit commitment process. A combined-cycle generator typically has about 1.5 times the inertia of a coal generator of the same size, so commitment changes from coal plants to combined-cycle gas plants increase synchronous inertia on the system.

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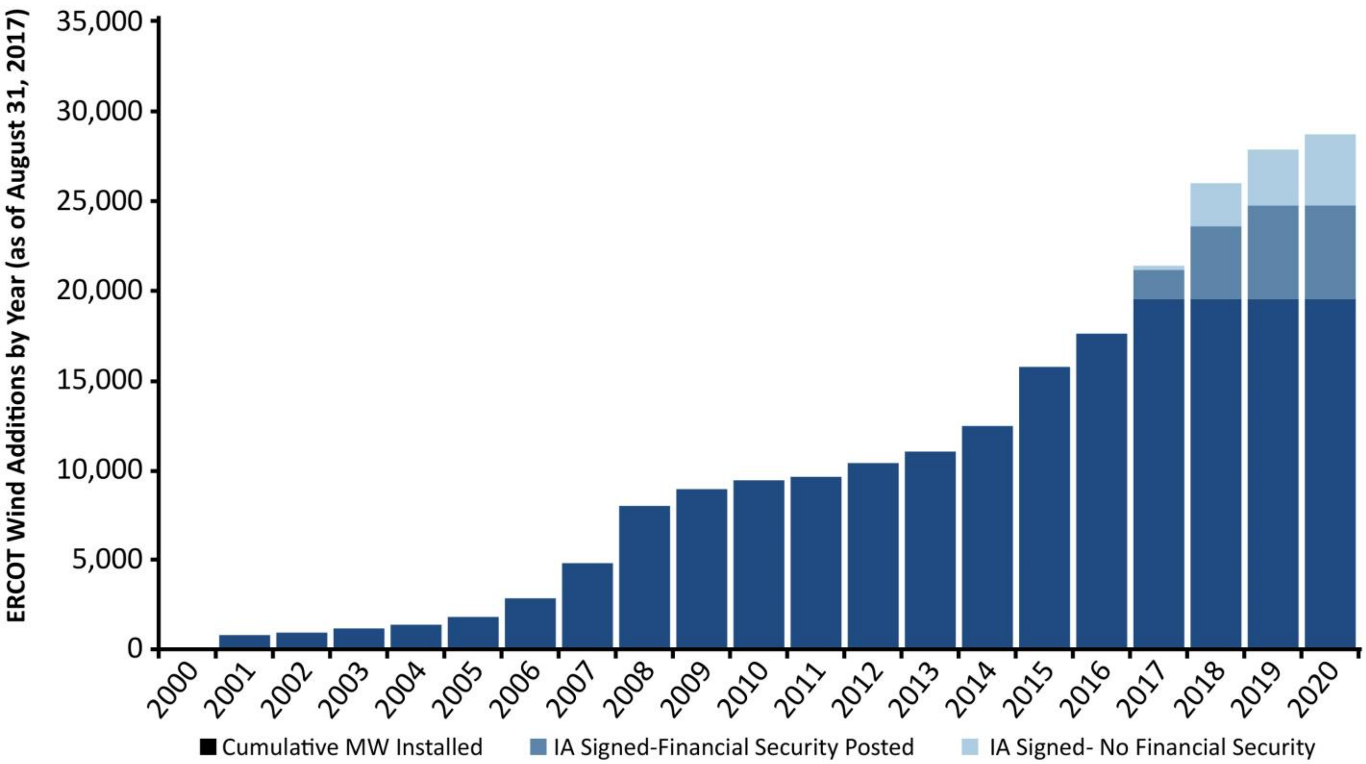
[10] The inertia calculation is based on individual unit production; if unit production is higher than a 5 MW threshold, then a unit is considered to be on-line and its inertia contribution is calculated as its inertia constant in seconds multiplied by the corresponding MVA base). Starting from 2017 the inertia calculation uses generator status to determine if a unit is on-line rather than a MW threshold.

[11] On each box, the central mark (inside the box) is the median, the lower and upper edges of the box are the 25th and 75th percentiles, the whiskers (dashed lines extending from each box) correspond to +/- 2.7 sigma (i.e., represent 99.3 percent coverage, assuming the data are normally distributed). The blue circles in the boxplot correspond to the system inertia when the highest portion of load was supplied by wind generation in a given year If necessary, the whiskers can be adjusted to show a different coverage.



Notes:

- The data presented here is based upon the latest information provided to ERCOT by resource owners and developers and can change without notice.
- Installed capacities for the current year account for changes reported by the facility owners during the reporting month and will be reflected in subsequent year totals.
- Installed capacities include only wind facilities that have registered with ERCOT (those larger than one megawatt and supply power to the ERCOT system).
- This chart reports annual planned units with projected commercial operations dates throughout the calendar year. In contrast, ERCOT's Capacity, Demand, and Reserves report shows planned capacity projected to be commercially available on or before the start of the summer and winter peak load seasons.
- Financial security posted for funding Interconnection facilities does not include CREZ security deposits, which are refunded to the interconnecting entity when an IA is signed.

Figure 2: ERCOT Yearly Wind Installations 2000–2020 (Installed & Projected)

Determining Critical Inertia Conditions

Following a resource trip, the rate of change of frequency (RoCoF) immediately after the event is solely a function of the inertia of the synchronous machines that are on-line and the magnitude of the lost capacity. Load resources with underfrequency relays providing Responsive Reserve Service (RRS) respond in about 0.5 second (30 cycles) after the frequency drops below the trigger level of 59.7 Hz.

ERCOT has defined critical inertia as the minimum inertia level at which a system can be reliably operated with current frequency control practices. Below critical inertia, frequency reserves may not have sufficient time to arrest system frequency before reaching the Under Frequency Load Shedding (UFLS) trigger level (59.3 Hz in ERCOT). Thus, for ERCOT, critical inertia is the inertia level below which frequency will decline from 59.7 Hz to 59.3 Hz in less than 0.5 seconds for a generation loss of 2,750 MW (i.e., the loss of ERCOT's two largest units). In other words, given current frequency control practices, there is not sufficient time for load resources providing RRS and other frequency reserves to respond and arrest frequency above UFLS trigger levels for a loss of this magnitude if system inertia is below this critical inertia level.

ERCOT conducted a series of dynamic simulations based on cases from TSAT[12] with inertia conditions ranging from 98 GW*s to 202 GW*s to investigate how long it takes for frequency to drop from 59.7 Hz to 59.3 Hz at each inertia condition. Using this analysis, ERCOT has identified its critical inertia to be 100 GW*s. To operate reliably below this inertia level will require changes to ERCOT's ancillary services. Faster response times for FFR, higher FFR frequency trigger values, and procuring inertia as an ancillary service are some of the options that can be considered. As shown in Table 1, the lowest system inertia value actually experienced in ERCOT through June 2017 was 132 GW*s.

Following this study, a three-level approach was implemented in the control room to provide operator awareness. **Figure 3** shows the information that an operator would see for different levels of low inertia. There is also an action plan in the control room for each of these levels:

- **≥110,000 MW*s to ≤119,999 MW*s:** the monitor shows the value highlighted yellow
- **≥100,001 MW*s to ≤109,999 MW*s:** the monitor shows the value highlighted orange
- **≤100,000 MW*s:** the monitor shows the value highlighted red and the operator has to take action to restore system inertia to above 100,000 MW*s.

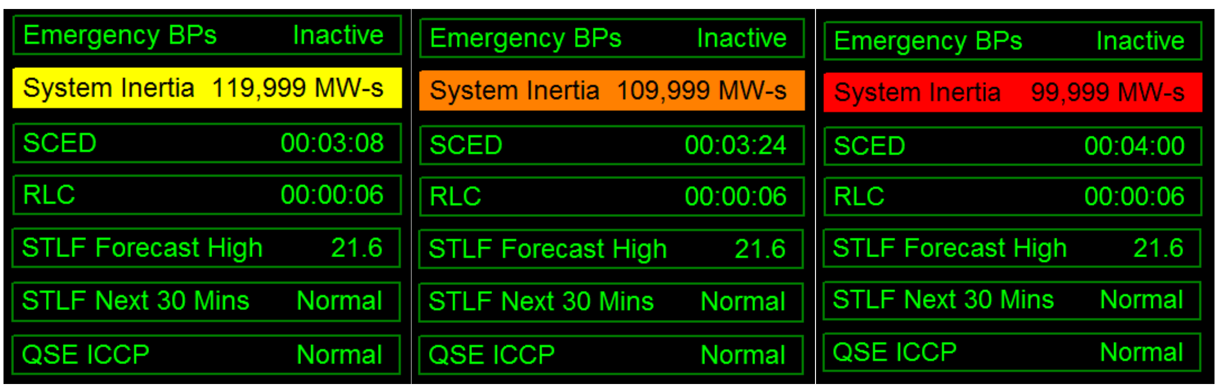


Figure 3: ERCOT Operator Information for Different Low Inertia Levels

ERCOT monitors and analyzes historic system inertia trends and is researching ways to more accurately forecast when the system is likely to reach critical inertia conditions.

Ensuring Sufficiency of Primary Frequency Reserves for Grid Conditions at or above Critical Inertia

ERCOT has developed a method to ensure primary frequency response availability by procuring RRS for use during generator trip events. Currently, RRS bundles two distinct functions within one service with this reserve service used as primary frequency reserve for frequency containment (i.e., to arrest frequency decline after a generator trip event) and also as a replacement reserve to restore depleted responsive reserves and bring the frequency back to 60 Hz. This paper focuses on the frequency containment function of RRS.

[12] ERCOT's Real Time Transient Security Assessment Tool (TSAT): http://www.dsatools.com/tsat/

There are two types of resources currently providing RRS in ERCOT:

- Generators deploying RRS though PFR (i.e., governor response with five percent droop when system frequency is outside of the deadband of ±17 mHz)
- Load resources, typically large industrial loads, deploying RRS through FFR (i.e., using underfrequency relays that automatically disconnect the participating load resources within 0.5 seconds when system frequency drops to 59.7 Hz or lower)

Until June 2015, ERCOT was procuring 2,800 MW of RRS for every hour of the year. Of the total amount of RSS that is procured, 50 percent can be provided by load resources with underfrequency relays through FFR with the remainder provided by generation resources through PFR.

In 2015, a series of dynamic studies were conducted by ERCOT staff to examine the minimum RRS requirements needed to prevent the frequency from dropping below 59.4 Hz (0.1 Hz above the prevailing first step of involuntary underfrequency load shedding) after the loss of the two largest generation units (2,750 MW). The study considered 13 cases at different system inertia conditions (from 100 GW*s to 350 GW*s).[13] The cases were based on ERCOT's real-time Transient Security Assessment Tool (TSAT).[14] Note that even though ERCOT requires governor or a governor-like response to be enabled on all generators connected to the transmission system, the study assumed that only resources that provide RRS were governor responsive. This assumption reflects a worst-case scenario where there is no governor responsive headroom on any generator other than generators providing primary frequency reserve. Load models in the cases included frequency sensitivity (load damping).

The study showed that more RRS is needed for low-inertia situations in order to maintain the security and reliability of the grid. **Figure 4** shows how much RRS is needed at each inertia level in a scenario in which RRS is provided solely by generation resources through PFR (i.e., without any load resource participation).

[13] The results of the studies have been communicated at the ERCOT stakeholder meetings: http://www.ercot.com/committee/fast/2015
[14] ERCOT's Real Time Transient Security Assessment tool (TSAT): http://www.dsatools.com/tsat/

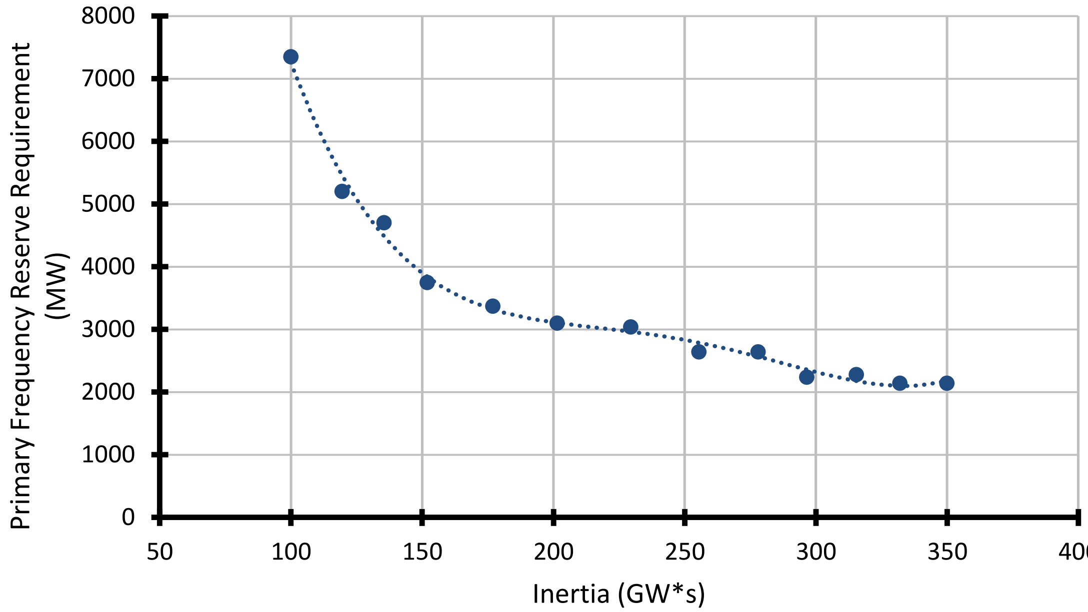


Figure 4: ERCOT Minimum Primary Frequency Response Reserve Requirement Under Different Inertia Conditions (assuming all RSS from generators without load resource participation)

In the same series of dynamic studies, it was found that, during low inertia periods, load resources that provide RRS using underfrequency relays are more effective at arresting frequency than generators providing RRS through governor response. For example, for 100 GW*s inertia conditions, 1 MW of load resources can be up to 2.35 times more effective[15] than 1 MW of PFR from the generators. (This value is referred to as the equivalency ratio (FFR/PFR)). The increased effectiveness is because the load resources provide full response within 0.5 second after system frequency reaches 59.7 Hz. This response is equivalent to a step change in active power injection. In low inertia conditions, system frequency declines faster after a generator trip, but it also increases faster following step injection of active power. Therefore, load resources are counted towards the total RRS requirement with the prevailing equivalency ratio (FFR/PFR), based on inertia conditions, as shown in **Figure 5**.

[15] For example, if the equivalency ratio is 2.35, it means that to replace X MW of PFR only X/2.35 MW of FFR is needed to provide the same arresting effect on system frequency.

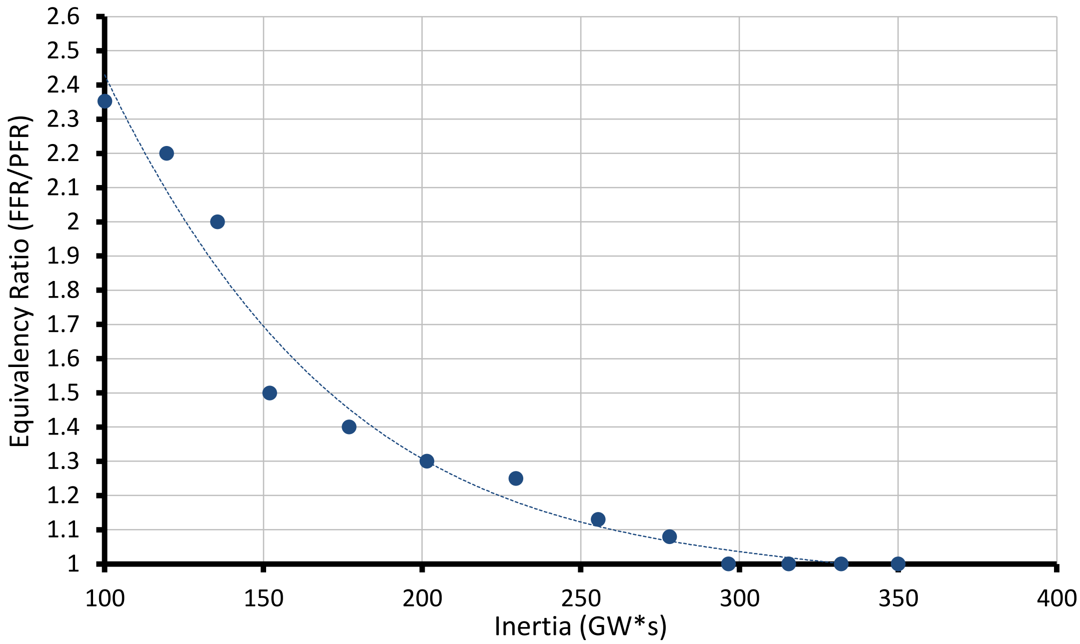


Figure 5: ERCOT Equivalency Ratio (FFR/PFR) Under Different Inertia Conditions

Procuring RRS quantities based on expected system inertia ensures that ERCOT will have sufficient frequency response to avoid UFLS after the simultaneous trip of the two largest units. **Figure 6** shows the frequency traces after tripping 2,750 MW of generation for the 13 inertia cases discussed above (with synchronous inertia from 100 GW*s to 350 GW*s). RRS amounts in each simulation in **Figure 6** are set to the requirement shown in **Figures 4** and using the corresponding equivalency ratio (FFR/PFR) from **Figure** 5 (with 50 percent of RRS in each case provided by load resources with an equivalency ratio corresponding to the synchronous inertia in the case). For all tested inertia conditions, the simulations confirm that procuring the RRS amount based on expected system inertia and the corresponding equivalency ratio between PFR and load resources ensures sufficient frequency response to avoid UFLS for the simultaneous trip of the two largest units.

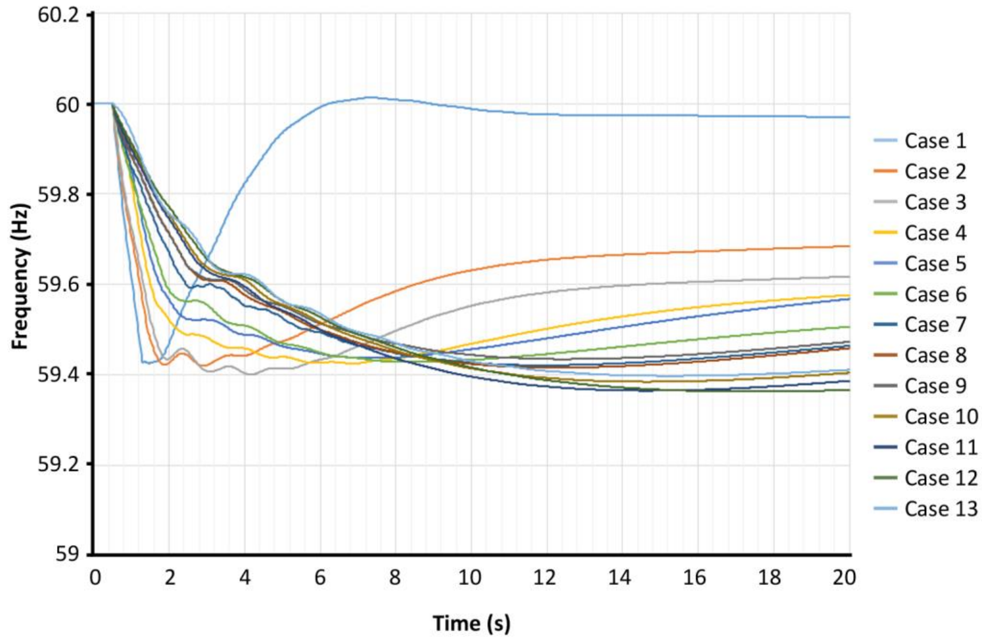


Figure 6: Case Study: Frequency Traces After Tripping 2,750 MW of Generation[16]

To assist in maintaining a sufficient amount of RRS, a new real-time tool was implemented in the ERCOT control room in March 2017. The tool continuously forecasts system inertia for day-ahead and real-time operations. Based on forecasted inertia conditions, the tool determines the required amount of RRS and compares it to the RRS amount procured in the day-ahead market. If the procured amount of RRS is not sufficient for the forecasted inertia conditions, a supplemental ancillary services market can be used to procure additional RRS.

[16] Case 1 corresponds to lowest inertia of about 100 GW·s and Case 13 corresponds to highest inertia of 350 GW*s.

Hydro Québec

Since 2006, HQ has applied a criterion in operations to protect against low inertia issues. The criteria called the PPPC[17] limit is defined as the maximum amount of generation that can be lost in a single contingency without tripping UFLS. This limit is established based on a relationship derived from a comprehensive dynamic study of the system considering different load/generation levels, contingency size and location, effect of synchronous reserve, load behavior, strategic power system stabilizers, etc.

The study for determining the PPPC limit is based on historic load and generation levels that represent a wide range of possible inertia levels, from the lowest to the highest over the past years. Generation dispatch patterns are updated automatically and simulated with different production levels of wind power plants to reflect the range of real-time operating conditions. Then, in each case, the maximum generation trip is determined by simulation so that the frequency will not drop below 58.5 Hz for a contingency event.

In addition to having the frequency trigger for UFLS at 58.5 Hz, HQ has established additional thresholds based on the RoCoF in their UFLS program. The UFLS thresholds that are based on the RoCoF are not part of the study for determining the PPPC limit because it is assumed that the amount of generation loss defined by the PPPC limit will not be sufficiently severe to trigger UFLS based on the additional RoCoF thresholds.

Based on the study, the PPPC limit is derived as a function of the synchronous generation that provides inertia (with a speed regulator effective) and the number (up to a maximum of five) of multi-band power system stabilizers on-line. The PPPC limit is directly proportional to synchronous inertia. **Figure 7** illustrates the strong correlation between the PPPC limit and synchronous inertia on the HQ system since the beginning of 2017.

[17] The term PPPC is an acronym in French : P = Perte = Loss, P = Production = (of) Generation, P = en Première = First (meaning “following a Single”), C = Contingence = Contingency.

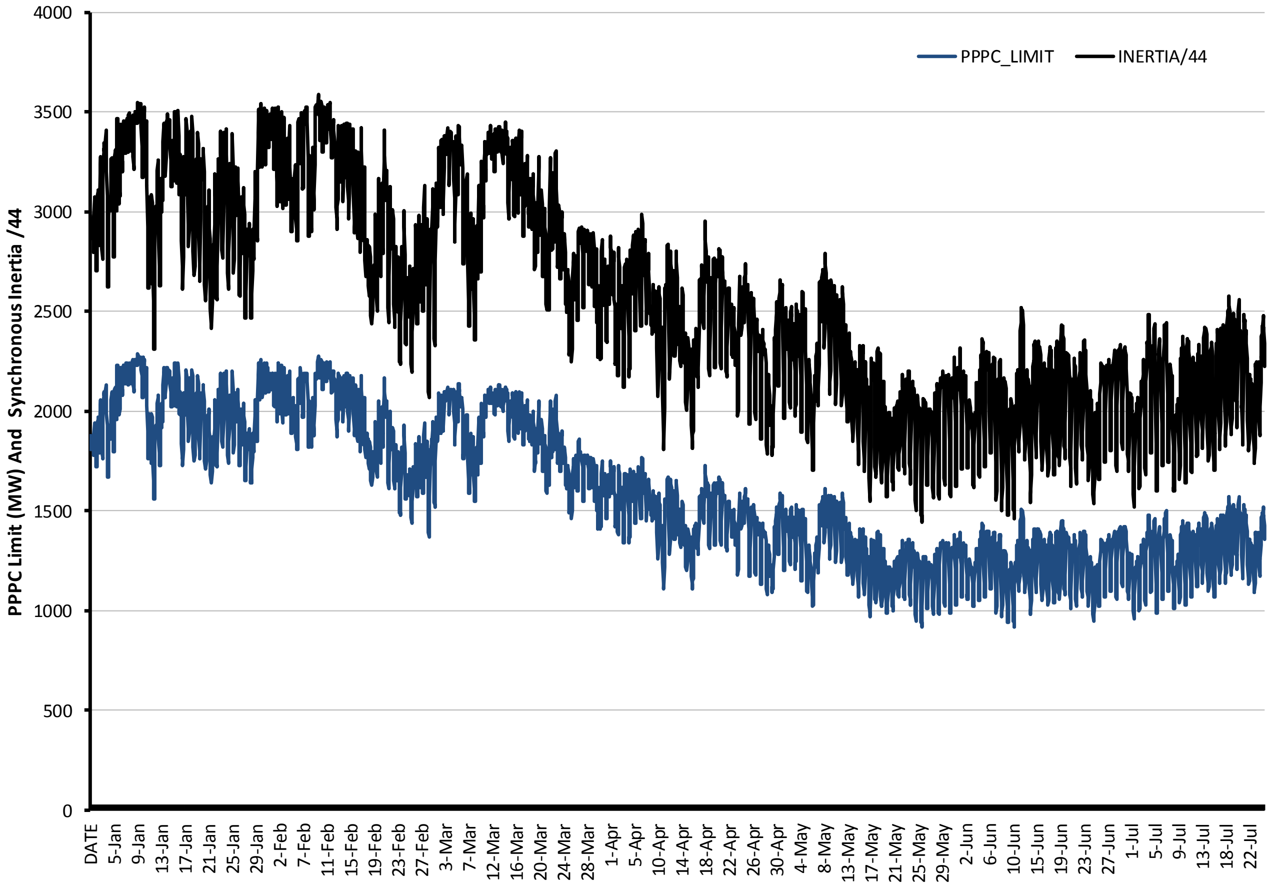


Figure 7 Correlation: PPPC Limit and Synchronous Inertia (January through July 2017)

In actual use, two different PPPC limits are calculated: a MW limit that is applicable to the synchronous generation (North) and a second MW limit that is applied to the flows over the DC ties (South). The two limits were created because the frequency drop following the loss of synchronous generation in the North is more severe than the frequency drop following the equivalent loss of import on the HVDC tie in the South. While the loss of HVDC import is only associated with loss of MW infeed, the loss of synchronous generation is also associated with the loss of inertia and primary frequency response of that generator. Therefore, the limit based on the loss of synchronous generation is more stringent than the limit based on loss of equivalent HVDC import. This more stringent value is what HQ calls the PPPC limit.

At this time, the effect of the synthetic inertia of the wind power plants, as required by HQ grid code,[18] is not included in the computation nor in the studies from which PPPC limit function is obtained.
To summarize, this PPPC limit represents the largest loss of power acceptable after a single contingency for given system conditions. It is computed in real-time and is strongly correlated to the amount of synchronous

[18] Technical Requirements for the Connection of Generating Stations to the Hydro-Québec Transmission System, December 2016: http://publicsde.regie-energie.qc.ca/projets/208/DocPrj/R-3830-2012-B-0075-Demande-Piece-2016_12_15.pdf

inertia on the system. For the year 2016, the PPPC limit has varied between 870 MW and 2,260 MW. For example, at a specific time, if the PPPC limit calculated is 2,000 MW and a loss of generation of 2,000 MW occurs, the frequency should theoretically drop to just above 58.5 Hz (i.e., close to the first UFLS threshold). **Figure 8** shows boxplots for the PPPC limit for years 2007 to 2017.

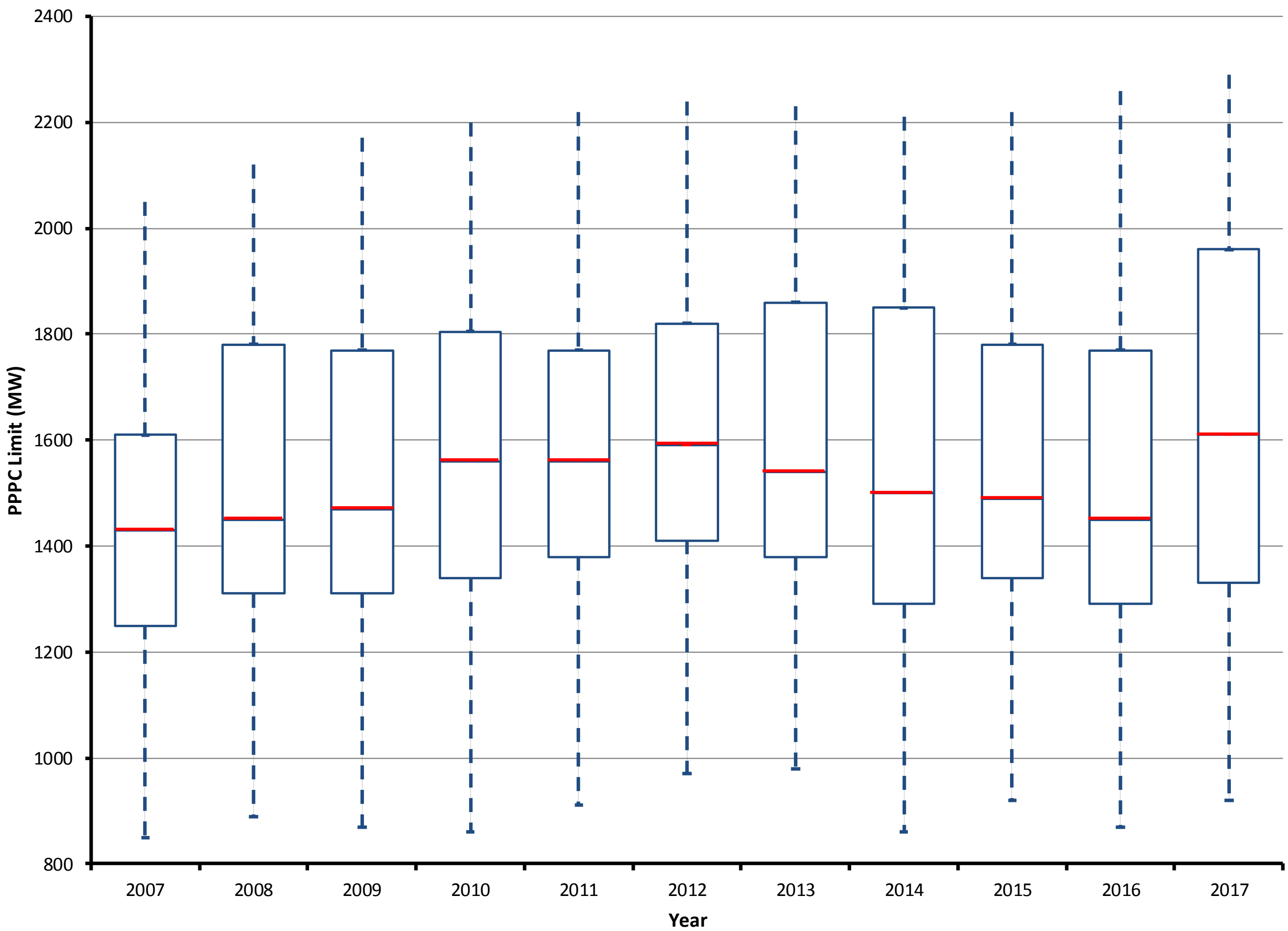


Figure 8:Hydro-Québec Boxplots for PPPC Limit for 2007–2017

HQ also has to evaluate the largest loss of generation possible at any time, depending on the actual topology of the network, to make sure that the largest contingency is below the PPPC limit. A real-time screening tool was specifically designed to continuously scan the entire network and identify the largest possible loss of generation following a single contingency event. This value is called the PPPC (not to be confused with the PPPC limit). An alarm is trigged when PPPC > PPPC limit and the system operators must take actions to either reduce PPPC (typically by generation re-dispatch) or increase PPPC limit (typically by adding synchronous generators or multi-band power system stabilizers). Transmission Operators consider both PPPC and PPPC limit when creating their day-ahead and hour-ahead forecasted generation dispatch.

Figures 9 and **10** compare the PPPC with the PPPC limit for the months of July 2016 and December 2016. Due to higher synchronous inertia, PPPC limit is usually higher during the winter period. The PPPC is always kept below the PPPC limit.

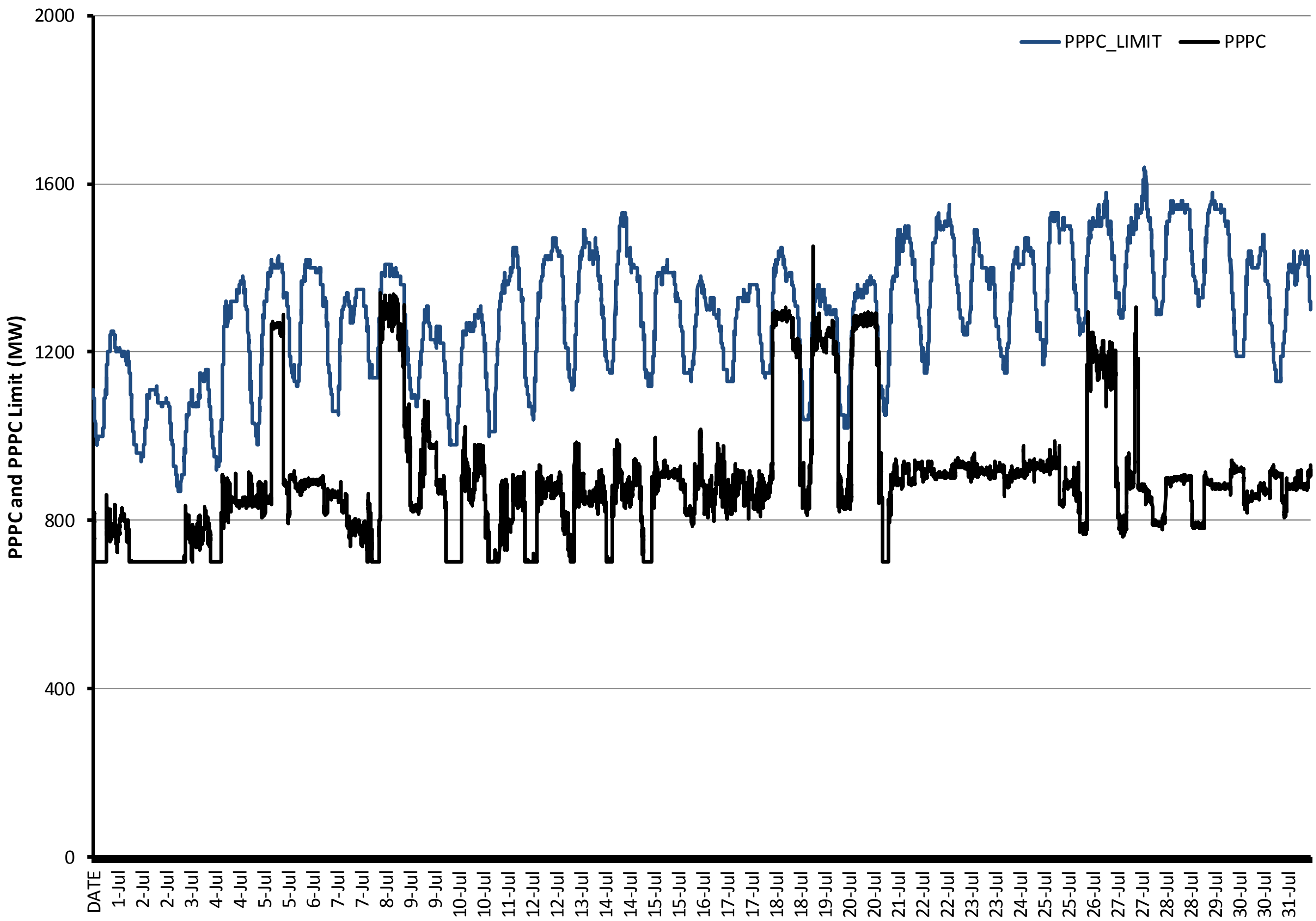


Figure 9: Hydro-Québec PPPC Limit and PPPC for July 2016

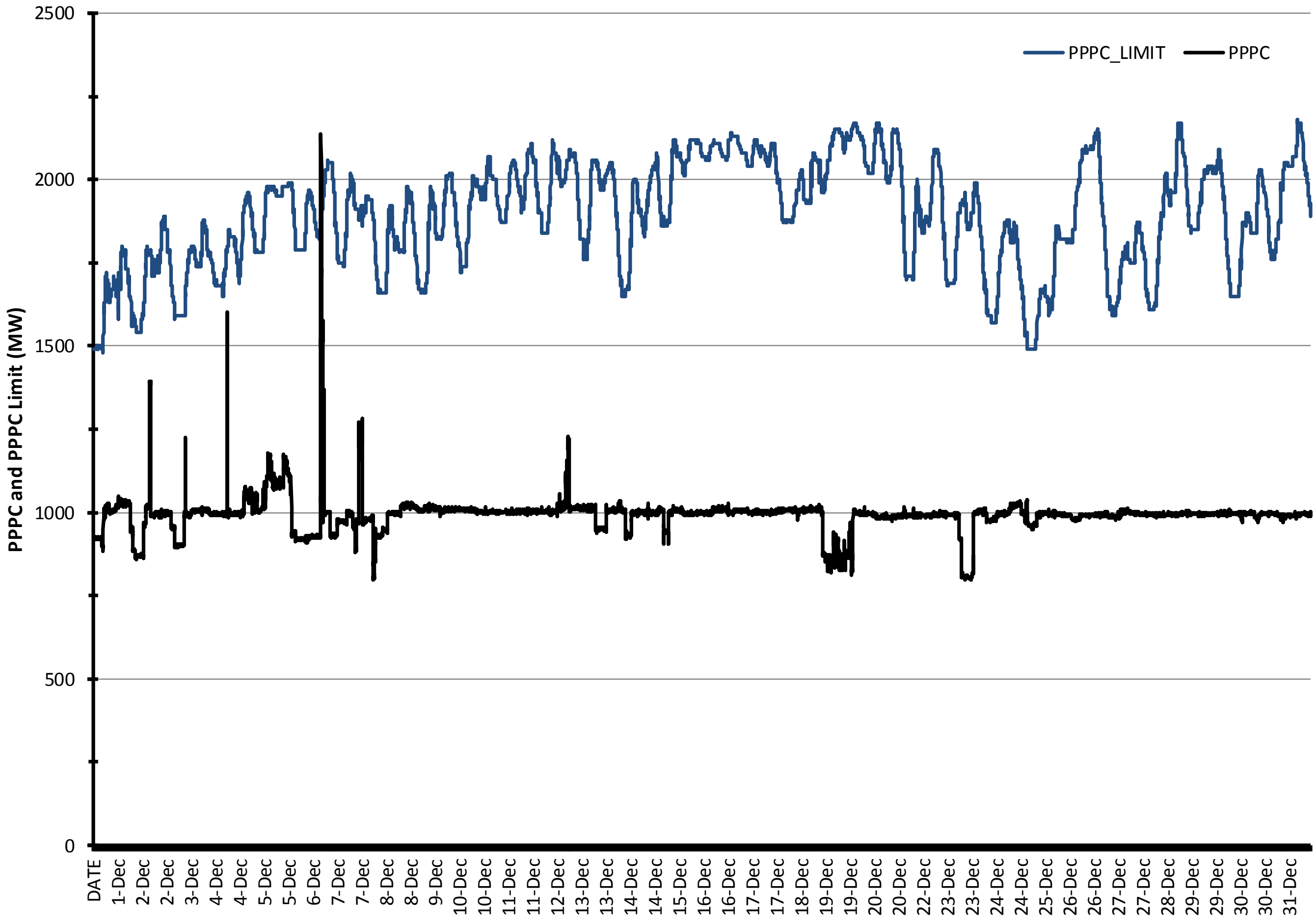


Figure 10: Hydro-Québec PPPC Limit and PPPC for December 2016

Eastern and Western Interconnections

In comparison to HQ and ERCOT, the Eastern Interconnection (EI) and Western Interconnection (WI) are physically larger, diverse systems that have not needed special strategies related to inertia conditions. Therefore, rather than conduct studies covering all possible inertia conditions as in the cases of HQ and Texas described above, it is practical to trend the frequency support measures (Measures 1, 2, and 4) historically and forecast future trends using EI and WI planning cases.

The ERSWG has worked with members of the EI and WI to develop a study process for future forward-looking frequency support measures as detailed below. The Eastern Interconnection Planning Collaborative (EIPC) and Western Electricity Coordinating Council (WECC) will lead this effort for the EI and the WI, respectively.

Eastern Interconnection

The EI Multiregional Modelling Working Group (MMWG) is developing planning cases for the EI that are suitable for future trending. **Table 2** shows the 2016 series of planning cases, which are five-year projections. The row highlighted in grey, Spring Light Load Season Case for Year 2021, represents the case that can be used as a starting point. In this case, the frequency response data set is adjusted to reflect the dynamic model data set that represents a more accurate frequency response in the EI (i.e., to more accurately model frequency response withdrawal behavior, also known as the “Lazy L”).

Table 2: Eastern Interconnection MMWG Planning Cases—2016 series						
Year	**Season**	**Power Flow Model**	**Dynamic Model**	**Study Model**	**Frequency Response**	**Load Modeling**
2017	Spring Light Load	X	X		X	
2017	Summer Peak	X	X	X	X	
2017/18	Winter Peak	X	X	X	X	
2018	Spring Light Load	X				
2018	Summer Peak	X				
2018/19	Winter Peak	X				
2021	Summer Shoulder	X				
2021	Spring Light Load[19]	X	X		X	X
2021	Summer Peak	X	X			X
2021/22	Winter Peak	X	X			
2026	Summer Peak	X	X			
2026/27	Winter Peak	X	X			

The first step is to validate the Light Load "Frequency Response" case using the data from a recent historic frequency event as follows:

1. Choose an event that happened at system conditions similar to the Light Load planning case (inertia data from June 2016 and later is available to the NERC RS).
2. Simulate the selected event using the Light Load planning case.
3. Compare the frequency response from the selected historic event to the simulated event. It is expected that frequency response will look different due to the simulation being conducted on a future planning case. However, it is important to analyze the differences between the responses and understand if governor models and deadbands in the planning case need to be modified to be more representative of the actual governor response on the system.

Once the frequency response event in the Light Load planning case is validated and any necessary modifications to governor models are made, it is then necessary to verify that unit commitment in the Light Load cases is representative of future low system inertia conditions. The following steps describe the process for evaluating the unit commitment in the light load case:

[19] Light Load Cases are based on Easter Sunday 2:00 a.m. assumption.

1. Use the Light Load case for 2017 (from 2016 case series).
2. Calculate the total system inertia in this case.
3. Compare the calculated system inertia to the minimum inertia reported from historic data for the year 2017 (The minimum inertia data for the system is readily available through the NERC RS via the historic Measure 1, 2, and 4 data collection and analysis process).
    a. If the historically reported 2017 minimum inertia is close to the calculated total system inertia from the planning case, then the unit commitment in the MMWG five-year light load case can be assumed to be representative of low inertia conditions.[20]
    b. If the calculated inertia from the light load planning case for 2017 (from 2016 case series) is not close to the historically reported 2017 minimum inertia, then the unit commitment in the light load planning case is not representative of low load/high renewable conditions. When this occurs, EIPC will modify the unit commitment and dispatch in the five-year light load case to arrive at a case that is representative of low inertia conditions.[21]

Once a planning case that is representative of low inertia conditions is created, future looking Measures 1 and 2 can be calculated as detailed in the ERSTF Framework Report. EIPC will then simulate the largest generation loss (currently 4,500 MW for EI as per BAL-003-1.1). The frequency response trace from the simulation will be used to calculate future looking Measure 4 as detailed in the ERSTF Framework Report. EIPC will then provide a report to NERC with the list of changes made to the initial Light Load planning case in order to perform the analysis, as well as feedback/suggestions on new cases that would be better suited for the frequency measures analysis going forward. Additionally, EIPC will also do the following:

- Provide feedback to the MMWG in order to improve their next round of case development.
- Identify data gaps to help the Planning Coordinators find problematic/bad data.
- Work with the WI to understand how they are developing Low Inertia cases.

[20] MOD32 defines what an asset owner has to provide in terms of dispatch into planning cases.
[21] Some of the results of production cost simulation studies from NREL and EPRI could be used to inform the commitment and dispatch process. The NREL Eastern Renewable Generation Integration Study: https://www.nrel.gov/grid/ergis.html

Modeling Improvement Efforts

To improve the analysis, the University of Tennessee Knoxville (UTK), Midcontinent ISO (MISO), and NERC have independently carried out frequency response studies and collaboratively recommended the following modelling improvements for EI MMWG Frequency Response cases:

- The total generation on-line with and without frequency response in the planning cases should more closely match the total generation on-line when compared to the system operations case. NERC will continue working with the Eastern Interconnection Reliability Assessment Group (ERAG) and MMWG to annually update dynamics case data and validate cases against system frequency events and a realistic operational dispatch. To perform a valid EI inertial analysis, the scenario must correspond to a reasonable operational dispatch.
- The NERC Changing Resource Mix study and NERC's analysis performed in response to FERC Order 794[22] found that the existing EI planning cases do not contain deadband modeling. The new governor models with deadband blocks available in PSS/E[23] version 33.10 (14 new governor model types) should be included in future base cases.
- Set governor deadbands at ±36 mHz or use actual deadbands as these become available.
- Some of the governors in the cases should be disabled. GE and UTK studies found that approximately 30 percent of the governors in the planning case should be in-service/frequency responsive to capture the governor response of the EI.
- Units that have outer-MW control loops should be identified. Governor models should be provided along with outer-MW control loop models (Turbine Load Controller Model) in order to represent the withdrawal of frequency response in the planning case.[24]
- To summarize the above three points, synchronous generation governors should be modeled to capture the governor response modes of various generators; specifically, whether they are Fully Responsive, Squelched, or Non-Responsive.
- Automatic generation control, remedial action schemes, generator protection schemes, and generator controls should be considered to capture mid-term dynamics behavior.

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[22] On January 16, 2014, in Docket No. RM13-11, FERC issued Order No. 794 approving the Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting). Reliability Standard BAL-003-1 defines the amount of frequency response needed from balancing authorities to maintain Interconnection frequency within predefined bounds and includes requirements for the measurement and provision of frequency response. In addition, Order No. 794 directed NERC to submit certain reports to address concerns discussed in the order. See, Frequency Response and Frequency Bias Setting Reliability Standard, 146 FERC 61,024 (2014). See, Informational Filing of the North American Electric Reliability Corporation Regarding the Light-Load Case Study of the Eastern Interconnection, Docket No. RM13-11-000, Appendix B (filed June 30, 2017)

[23] Power System Simulator for Engineering is a software tool used to simulate electrical transmission networks in steady-state conditions as well as over timescales of a few seconds to tens of seconds.

[24] See, Informational Filing of the North American Electric Reliability Corporation Regarding the Light-Load Case Study of the Eastern Interconnection, Docket No. RM13-11-000, p. 13 (filed June 30, 2017) (stating, "Automatic generation control (AGC), remedial action schemes, generator protection and controls, and outer-loop plant controls should be considered to capture mid-term dynamics behavior.") (reflecting the improvement in the data quality and fidelity of the case studied in 2017 in comparison to those present in dynamics cases at the start of the Frequency Response Initiative in 2010. A key aspect of the 2017 study was the benchmarking of the base case using model validation techniques. A significant amount of modeling improvements were made over several years before the beginning of this study. Base case model validation and detailed scrutiny of dynamics models of generation (e.g., governor models) played a major role in the improvements to the 2017 light loading base case studied.).

- Industry should work directly with software vendors to improve the dynamics models of new technologies such as inverter-based resources and wind generation.

Western Interconnection (WI)

WECC is producing a set of operations and planning cases for the WI every year that are similar to the MMWG cases in the EI. **Table 3** shows the 2016 series of planning cases, which are five-year projections.

Table 3: WI Planning Cases—2016 Series[25]

Year	Season	Power Flow Model	Dynamic Model	Load Modeling
2017/18	Heavy Winter	X	X	X
2017/18	Light Winter	X	X	X
2018	Heavy Spring	X	X	X
2018	Heavy Summer	X	X	X
2018	Light Summer	X	X	X
2019/20	Heavy Winter with South-North flows through California	X	X	X
2021	Light Spring	X	X	X
2022/23	Heavy Winter	X	X	X
2023	Heavy Summer	X	X	X
2027/28	Heavy Winter	X	X	X
2028	Heavy Summer	X	X	X

Unlike for the EI, WECC does not create frequency response cases. Separate frequency response cases are not required as all planning cases have a corresponding dynamic data sets that represent accurate governor response. Generator Operators of large generators[26] are directly providing their respective governor test results to WECC. Additionally, the planning models include a base load flag for the generators, which can block the governor response on the units in the model. As shown in **Table 3**, WECC currently only creates Summer and Winter Peak cases. However, these have been evaluated in comparison to actual historic events and are therefore are well benchmarked cases.

WECC will follow the same process for forward looking frequency studies as described previously in the EI section of this paper. Working with transmission planners in their area, these cases can be modified to create a low inertia case for the five-year forward looking timeframe. In addition, it may be possible to adapt the methodology for the unit commitment and dispatch approach from the NREL Western Wind and

[25] WECC Guideline, 2017 Base Case Compilation Schedule, July 7, 2016

[26] The WECC Generator Testing Policy asks for all generators 10 MVA or larger or plants 20 MVA or larger connected at 60 kV or higher to be tested.

Solar Integration Study[27] to further enhance each case. The proposed next steps for WECC include collaborative work with UTK on improving governor modeling in the planning cases.

Eastern and Western Interconnection Next Steps

Depending on efforts involved in producing forward-looking Measures 1, 2, and 4 studies, the EI and WI may determine the periodicity of the analysis. The current proposal is to repeat the forward looking frequency response studies every two to three years using the five-year future planning cases. The forward looking Measures 1, 2, and 4 process will continue to be updated with historic Measures 1, 2, and 4 data.

Both EI and WI will provide study reports to NERC with their required study cases. EIPC and WECC may also develop a procedural manual for this work so that it can be repeated in the future on a defined periodic basis.

[27] NREL Western Wind and Solar Integration Study: https://www.nrel.gov/grid/wwsis.html

Appendix A: Synthetic Inertia Requirements of Wind Power Plants in Hydro Québec

Hydro-Québec has included a synthetic inertia requirement from every wind power plant with a rated power of greater than 10 MW.[28] Wind power plants with a rated power greater than 10 MW must also be equipped with a frequency control system. Such a system enables wind generating stations to help restore system frequency in the advent of disturbances and thus maintain the current level of performance with regards to frequency control on the Transmission System. Different requirements apply to underfrequency conditions (during which the system relies on the inertial response of wind generators) and overfrequency conditions (where the system relies on continuous frequency regulation), as detailed below.

Underfrequency Control (Inertial Response)

The inertial response takes the form of a momentary overproduction that limits the frequency drop after a major loss of generation on the system. This control system will only be used to handle significant frequency variations, but it must remain in service continuously. For disturbances that bring underfrequency (< 60.0 Hz) conditions, the inertial response system used to comply with this requirement must assure system performance levels with the following characteristics:

- Full overproduction activated at a given frequency threshold or overproduction proportional to frequency deviation
- Deadband adjustable from -0.1 Hz to -1.0 Hz with respect to nominal frequency (60 Hz)
- Maximum momentary real power overproduction equal to at least 6% of rated power of each wind generator in service
- Rise time to reach maximum overproduction limited to 1.5s or less
- Real power decrease during energy recovery (if needed) limited to approximately 20% of rated power
- Should be available from every wind generator in service whenever their generation level reaches approximately 25% of the rated power
- Able to operate repeatedly with a 2 min delay after the end of the recovery period following the previous operation

Wind power plant performance takes precedence over individual wind turbine performance. The power producer must demonstrate the operation and performance of the inertial response system design based on tests performed on actual wind generators. The transmission provider may also consider any other solution that would allow it to reach the same performance objectives with regards to underfrequency control.

[28] Technical Requirements for the Connection of Generating Stations to the Hydro-Québec Transmission System, December 2016 : http://publicsde.regie-energie.qc.ca/projets/208/DocPrj/R-3830-2012-B-0075-Demande-Piece-2016_12_15.pdf

Overfrequency Control (Primary Frequency Response)

In order to handle overfrequency disturbances (>60.0 Hz), every wind generator within a wind power plant must be equipped with a frequency control system with a permanent droop (sigma) adjustable over a range of at least 0 to 5 percent and a deadband adjustable between 0 and 0.5 Hz.