Minutes
Essential Reliability Services Working Group

August 3, 2016 | 12:00 – 5:00 p.m. Eastern Time
August 4, 2016 | 8:00 a.m. – 12:00 p.m. Eastern Time

NERC Atlanta Offices
3353 Peachtree Road NE, Suite 600
Atlanta GA, 30326
Room: 611/12 – 6th Floor

Remote Participation:
Web: https://www.readytalk.com/?ac=5494366 | Access: 5494366 | Security: 160803
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NERC Antitrust Compliance Guidelines and Public Announcement - Done

Agenda Items
August 3, 2016

1. **Lunch –** Provided
2. **DER Workshop Review –** Pooja Shah, Todd Lucas, Brian Evans-Mongeon – Brian and Todd provided an update on the DER workshop and feedback received from it. The group went over the 7 comments received. Most comments were surrounding the definition of DER. There was a suggestion to bring the DER definition in middle of IEEE 1547 which is too short and NERC's proposed definition that is too wordy. Another suggestion was to break down the DER definition into 1) synchronous DER and 2) Asynchronous DER. There was a discussion on including NERC's functional model portion of LSE, DP in the final report. The discussion was that FM doesn't define the registration process and wouldn't be insightful. However, Chapter 5 group under Jason and Gary that will review pertaining standards will review the FM applicability.
3. **Co-chairs' remarks –** Todd Lucas, Brian Evans-Mongeon - Done
4. **DER Support Continuation for Standards Committee –** ~~Sean Cavote~~ Darrell Richardson, NERC – Darrell Richardson provided an update to the group regarding retaining the DER expertise for standards drafting committees in future.
5. **Discuss ERS Subgroup Activities** – Sufficiency Guidelines
   a. Frequency Support – Julia provided an update to the group on Frequency groups work. Since last time, there were some changes to the document. If no further changes, then the document is ready to be incorporated in the sufficiency guideline document.
   b. Load Ramping – Rodney provided an update to the group regarding the document on sufficiency. After the middle of August it's expected to be ready for the final document.

6. **Break**
7. **Discuss ERS Subgroup Activities (cont'd)**
   a. Voltage Support – John updated the group on status of reactive document. It has been reviewed by the SAMS group. If there are no more updates, it's ready to be incorporated in the document. SAMS group is working on a summary document for the reactive reliability guideline – to incorporate in the final document.
   b. DERTF – Most chapters well covered, waiting on chapter 5 on standards review. The next step is to document the front section of the report.

August 4, 2016 (No Breakfast)

1. **Monitor, Track and Trent ERSTF Measures with Subcommittees**
   a. RS and RAS – Troy, ~~Pooja~~ – Troy provided the group with the thorough review of the RS' work on Frequency review for measures 1-3, and measuring inertia as well as RoCoF. Troy also provided an update on their work with Measure 6 and monitoring CPS1 score on hourly basis. The RS group has done tremendous work on these measures and provide an example of real support to ERS work.
   b. PAS – ~~John Simonelli~~. PAS is said to be working on Measure 7
   c. RAS – Pooja RAS is working on testing Clyde's flow chart process for determining ramping issues. We have results from few areas who followed the ERSTF report and presented their results. The results will be incorporated in LTRA.
2. **Next Meeting**
   a. September 14-15, 2016 – Phoenix, AZ – following OC and PC Meetings
   b. Week of November 7, 2016 – Portland, OR – Tentative
   c. December 14-15, 2016 – Atlanta GA NERC Offices
3. **Close Meeting**

Essential Reliability Services Working Group / Distributed Energy Resources Task Force Working Meeting

Wednesday, August 3, 2016 at 1:00 PM - Thursday, August 4, 2016 at 12:00 PM (EDT)
NERC Headquarters - 3353 Peachtree Road NE - 6th Floor, North Tower - Atlanta, GA 30326

	Last Name	First Name	Qty	Ticket Type	Payment Status
✓	Ahlstrom	Mark	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526747483
	Antonakos	John	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-529620460
	Antonakos	John	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-529610273
✓	Assaturian	Sasoon	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-527993653
✓	Brown	Layne	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-536379179
✓	Busby	David	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-532928493
✓	Canter	David	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526897769
✓	Clark	Kara	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-530145657
✓	Clarke	Andrew	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-535842809
✓	erickson	sean	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-536676485
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✓	Evans-Mongeon	Brian	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-527230931
✗	Gordon	Brad	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-537413711
✓	Hamdar	Hassan	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-536900566
✓	Hotchkiss	Cindy Ceh	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526752559
✓	Hydzik	Rich Hydzik	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526760786
✓	Kang	Ning	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-529898126
✓	Keenan	Gerald	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-536000020
	Le	Quoc	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-528396317
✓	Loutan	Clyde	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-534352845
	Lulalo	Olushola	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526916128
✓	MacDowell	Jason	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-536397471
✓	mandavilli	jagan	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526746865
✓	Matevosjana	Julija	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526830512
✓	Mather	Barry	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-536302557
✓	Mather	Barry	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-536302780

Essential Reliability Services Working Group / Distributed Energy Resources Task Force Working Meeting

	Last Name	First Name	Qty	Ticket Type	Payment Status
✓	McCurley	Paul	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-527029838
	Mosher	Allen	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-529680785
✓	Nethercutt	Elliott ETN	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526906634
✓	O'Bryant	Rodney	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-532194178
✓	OSMAN	Mohamed	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-527367070
✓	Ramasubramanian	Deepak	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526916148
✓	Reilly	Jim	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-527597526
✓	Shah	Pooja	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-527567482
✓	Siegrist	Tom	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-526980918
✓	Simonelli	John	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-530350827
✓	Singhvi	Vikas	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-535294669
✓	Spencer	Joe	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-536655994
✓	WU	MING	1	Essential Reliablity Services Working Group Tickets	Free Order Order 26060969060-532863627

Bob Cummings NERC 1

Smith Charlie 1 " "

Shirmohammadi Darush 1 " "

Troy Blalock SCEG/NERC RS " "

LUCAS, TODD

Darrel Richardson, NERC

Mulhern, Joseph, PJM

Corbett, Alfred, FERC " "

Brant Werts Duke ?

John Moura

Phone Maggie Peacock

Voltage and Reactive Sub-area Concept Paper

ERSWG Voltage and Reactive Subgroup

Voltage regulation and reactive resource management is a critical part of planning and operating the Bulk Electric System (BES). Maintaining adequate voltage profiles across the BES both pre and post contingency is a function of the reactive resources available and their utilization. Low voltage events can cascade creating a wide spread event and, while high voltage events do not necessarily cascade, they can result in serious equipment damage. The ability to control the production and absorption of reactive power often becomes the driving force behind studying and operating the BES over a wide range of conditions, especially in those areas where weak transmission systems supply load and generation or the transmission network can be subjected to heavy power transfers.

So while engineers must consider voltage and reactive performance over a wide range of system conditions there is a significant justification for focusing the analysis on much smaller sub-areas of the BES. Due to the lack of transportability of reactive resources on the BES, planners and operators need to consider defining sub-areas of the BES within their footprint that have their own unique set of voltage / reactive performance issues which only lend themselves to local resources and remedial actions. The BES varies widely from area to area based on the specific topology and electrical characteristics. There has been a long held belief in many industry sectors that reactive resource reserves are the key to maintaining a robust system. While at a high level this is true, the reality is if those abundant reactive reserves are not electrically close to where they are needed, they are likely to ~~will~~ be totally ineffective in managing voltages on the system.

Therefore the Planning Coordinator and Transmission Planner, based on their knowledge of the unique characteristics of their system, should collaboratively develop criteria for defining "reactive power sufficiency" sub-areas within their footprint. They should also involve the Reliability Coordinator and Transmission Operator who may have useful insight into sub-area characteristics based on operational experience in the selection process. Logical sub-areas can and are likely to cross company boundaries and jurisdictional boundaries; they should be developed solely on electrical characteristics and reactive performance.

Consider the inherent difference between a typical large urban area and that of a typical large rural area in such variables as load level and load power factor (LPF), various overhead and underground transmission network configurations, dynamic and static reactive resources and, the appropriate minimum and maximum voltage limits to adhere to. While these two areas may be within the same RC/BA/PC footprint the voltage both low voltage at heavy load periods and high voltage at light load periods and reactive performance of each can vary significantly.

That difference will drive both the criteria and the type of planning studies required to meet the objective of developing a robust reliable system. Similarly those same differences may impact the way the real-time operations are managed. The determination of appropriate sub-areas within the larger footprint becomes the primary and most critical first step in planning and operating the BES from reactive power sufficiency standpoint. Considerations in defining sub-areas of the system are:

- Reactive performance within the footprint both pre and post contingency
  - Insufficient reactive compensation in a single area can impact or cascade to neighboring areas and affect overall BES operation
  - The system can reach a state where even though voltages appear to be within the normal range~~adequate~~, most available reactive resources are exhausted and the next contingency can degrade voltages and reactive performance pushing the BES quickly into unacceptable performance
  - The loss of high voltage BES facilities can load remaining facilities more heavily and result~~ing~~ in significantly increased losses which will negatively impact the voltage profile and reactive resources
  - Outages of major reactive resources not only removes the reactive capability but can also result in large MW swings and increased losses which will negatively impact the voltage profile and reactive resources
- Real power import, export, and flow-through characteristics, e.g. large power transfers within or between sub-sets can significantly increase reactive power losses which will negatively impact the voltage profile and reactive resources
- Transmission topology and characteristic, e.g., high surge impedance loading where real power transfers can reach a point where reactive consumption of the transmission system exceeds available reactive supply which will negatively impact the voltage profile
- Charging from cables or long overhead lines during light load periods where these facilities may produce voltages so high that leading reactive capability is exhausted and circuits must be opened to reduce voltages
- Types of reactive resources available which will have different lead/lag characteristics:
  - Synchronous generators and condensersvs ~~vs.~~
  - N~~n~~onsynchronous/inverter based resources,
  - Static devices, i.e., shunt capacitors, reactors, etc,
  - Dynamic devices, i.e., SVCs, STATCOMs, DVARS, etc,
  - HVDC terminals, such as Voltage Source Converters that can supply reactive capability,
  - Line compensation that can be switched in and out such as series compensation.
- Real and reactive load distribution, (while this is the distribution area of the system, real load and LPF can have both a positive and negative impact on the BES and that contribution must be accounted for). It is important that the transmission and distribution systems be coordinated when managing reactive power transfer into and out of the distributions system. This will result in an effective optimization of installed reactive resources on each system to improve reliability and reduce cost.

Once appropriate ~~subarea~~sub-areas have been defined, the planners and operators must ensure compliance with all applicable NERC standards. More stringent regional or local criteria may also be utilized.~~This does not mean that more stringent regional or local criteria may also be utilized~~. The planners and operators would then need to develop appropriate sufficiency measures applicable to each unique sub-area. Sufficiency measures can and most likely will differ by sub-area based on their reactive power characteristics. As an example a large urban area that has limited reactive resources and routinely imports large amounts of real power may have a more stringent min/max voltage limits. It may further have certain online dynamic reactive resources and load power factor requirements. A rural sub-area with relatively light real power loads and long high impedance overhead lines may have more relaxed min/max voltage limits and may need to maintain a specific reactive reserve. The point to reinforce is that reactive power sufficiency requirements by sub-area need to fit the reactive characteristics of the specific sub-area in order to ensure reliability is maintained and a certain degree of reactive power performance robustness is built into the system. Reactive power sufficiency measures therefore are not one size fits all. Potential sufficiency measures for sub-areas can be seen in the table below.

Table 1

Potential Sub-area Sufficiency Measures

Potential Sufficiency Measures	Sub-area A	Sub-area B	Sub-area C	Sub-area D
Pre contingency Min/max voltage	1.01/1.04	0.98/1.04	0.98/1.045	1.01/1.04
Post contingency min/max voltage	.95/1.05	.92/1.05	.90/1.06	.95/1.05
On-Line reactive reserves	Minimum of 3 generators in the sub-area, 100 MVA or greater, on-line above 80% load level	n/a	1 generator on line at all times, 2 of 3 SVC on-line at all times, within the sub-area	n/a
MW dispatch	Commit 1/3 of fast start resources at 95%	n/a	n/a	n/a

	load level			
Min LPF required at heavy load periods	0.98 lagging	0.96 lagging	0.94 lagging	0.80 lagging
Max LPF allowed at light load periods	0.98 leading	0.97 leading	0.99 leading	0.98 leading
MW Imports	Limit pre contingency import into the sub-area to 90% of maximum capability	n/a	n/a	n/a
Line/Cable switching	n/a	n/a	Remove 2 of 8 cables in the sub-area at load levels below 40%	Open 1 of 4 possible overhead lines within the sub-area at load levels below 30%
Static reactive resources	All BES capacitors on-line above 85% load	n/a	All BES shunt reactors on-line below 50% load	n/a

In a general sense the defined ~~subarea~~sub-areas ~~that are defined~~ should be somewhat autonomous relative to their reactive and voltage performance for N-1-1 conditions. This construct negates one ~~subarea~~sub-area relying too heavily on adjacent ~~subarea~~sub-areas for reactive support thereby increasing the chance of a cascading event. This also inherently builds in reactive margin so that in real-time where N-k events may occur there is enough robustness to prevent a widespread event from occurring. The end result is to plan and operate each sub-area so that the reliability of the broader BES is maintained. There are numerous tried and true methods of studying, planning, building and operating the BES. At a high level those aspects are addressed in the accompanying NERC Reliability Guideline: Reactive Power Planning and Operations.

Abstract for tech document

Synchronous inertia sufficiency guideline

The purpose of this guideline is to examine the system capability under low inertia condition to arrest frequency decay and avoid involuntary under-frequency load shedding after large generator trip based on each region's existing primary frequency control capabilities and practices. Once system inertia, based on historical data (Measure 1&3) starts approaching a critical value, as described in this document, each region should consider revising the existing frequency control practices and capabilities and introduce additional measures to ensure system frequency is arrested above the prevailing first stage of involuntary under-frequency load shedding after the largest contingency.

Keeping a minimum level of synchronous inertia may not be the most efficient way to operate the grid. Out of market unit commitment for inertia may have adverse effect on market prices. Generators committed for inertia will operate at least at their minimum stable production level affecting energy prices and potentially causing curtailments of non-synchronous generation. Thus, it is recommended that other fast frequency control measures to address decreasing inertia trend are implemented. *Fast frequency response is active power injection automatically deployed in the arresting phase of a frequency event, aimed at providing full response before the frequency nadir is reached.* Several examples of fast frequency response are provided below:

1. In ERCOT Load Resources with under frequency relays are providing a portion of Responsive Reserve Service (Ancillary Service with a function to arrest, stabilize, and recover frequency after an event). These Load Resources trip offline, providing full response within 0.5 second[1] after system frequency falls at or below 59.7 Hz. This capability can be viewed as fast primary frequency response. This type of response, i.e. response to a frequency trigger, is very efficient at arresting frequency after an event. Battery storage can be used for the same purpose, i.e. to provide full response very quickly once the system frequency reaches a certain threshold. Time of response and frequency triggers can be optimized to meet particular system needs.

2. Hydro Quebec has adopted a different approach to address low synchronous inertia concern. In 2006 they have updated their grid code with specific requirement for emulated (or synthetic) inertia response requirement for wind power plants (WPPs). WPP frequency control must reduce large, short-term frequency deviations at least as much as the inertial response of a conventional generator whose inertia constant equals 3.5 s does [Ref to GC document]. Simulations have shown that this target performance is met, for instance, when the wind turbine generators vary their active power dynamically and rapidly by about 5% for 10 s when a large frequency deviation occurs. This requirement is still in effect. Synthetic inertia from wind generation is another means of very fast active power injection that can help address high initial rate of change of frequency (RoCoF) after a contingency.

[1] Underfrequency relays at the participating load resources in ERCOT have a time delay set at 0.33 seconds (or 20 cycles). The timer will start after triggering frequency is reached and will reset if the system frequency increases above triggering frequency during that period. This delay is introduced to avoid nuisance tripping, but the time can potentially be reduced. Additionally, about 0.17 second (or 10 cycles) is necessary for a breaker to open and disconnect a load resource. This time delay is based on physical capabilities of a breaker.

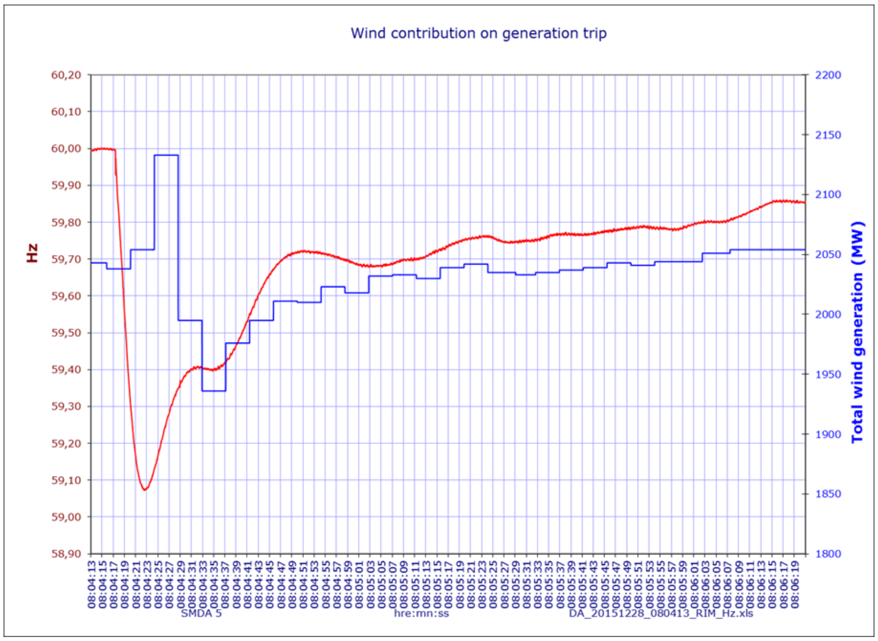

Figure 1: Synthetic inertia response from wind generators in Hydro Quebec after generator trip event.

The methodology for determining critical synchronous inertia under existing frequency control practices

The flowchart for the proposed methodology is shown in Figure 2.

1. Calculate system inertia for every hour in a year in MVA*seconds. This is calculated as a sum of individual inertial contributions from all online generators. Find the lowest inertia instance in a year. This is basically covered under Measures 1& 3 developed in ERSTF Framework Report.
2. At that lowest inertia condition, calculate Rate of Change of Frequency (RoCoF), Hz/s based on the Interconnection's resource contingency criteria (RCC), which is the largest identified simultaneous category C (N-2) event, except for the Eastern Interconnection, which uses the largest event in the last 10 years. This is a part of the Measure 2 calculation. Note there is no standard requirement for a system to operate without shedding firm load after RCC event, rather this is the best practice for the system design.
3. With the RoCoF from the previous step, calculate how long it takes to reach the first stage of under frequency load shedding (UFLS) after the RCC event. If this time is sufficient (e.g. 1-1.5 seconds[2]) for the existing means of frequency response (fast frequency response, primary

[2] The purpose here is to make sure the RoCoF does not result in UFLF within 1-1.5 s, i.e. before frequency response (fast and/or primary) can become effective. Times when fast and primary frequency response becomes affective may vary for different systems and different synchronous inertia conditions. Those could be verified from historic

frequency response) to start deploying and to help arrest frequency above the first stage of UFLS, then this RoCoF is not critical.

4. Gradually, scale down the inertia found in step 1, in steps of, say 10%. Repeat steps 2 and 3, until the resulting RoCoF is such that a Prevailing UFLS First Step is reached before the primary frequency response can become effective (e.g. for ERCOT this time is 1-1.5 second during low inertia conditions in). Return to the last inertia value that still is sufficient. This is the first approximation of the critical system inertia.

   Note: *The Eastern Interconnection 59.5 Hz UFLS set point listed in BAL-003-1.1 is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba. Since this UFLS setting only applies for local considerations. It is meaningful to use 59.5 Hz as a frequency threshold for the calculation steps 1-4 above.*

Commented [MJ1]: Can we find similar information from event analysis for other interconnects.

We need to add another paragraph or a text box here may be showing how the timeframe when PFR starts showing can be determined from the event analysis.

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event analysis and dynamic simulations. For example in ERCOT Load Resources with under frequency relays are providing a portion of Responsive Reserve Service (Ancillary Service with a function to arrest, stabilize, and recover frequency after an event). These load resources trip offline within 0.5 second after system frequency falls at or below 59.7 Hz. Therefore, in ERCOT, the RoCoF that leads to 59.7 Hz within few hundred milliseconds after an event and the then first stage of UFLS within the next 0.5 second, becomes important. If UFLS is not reached within this time frame, Load Resources would trip and would be very efficient at arresting frequency above the UFLS threshold.

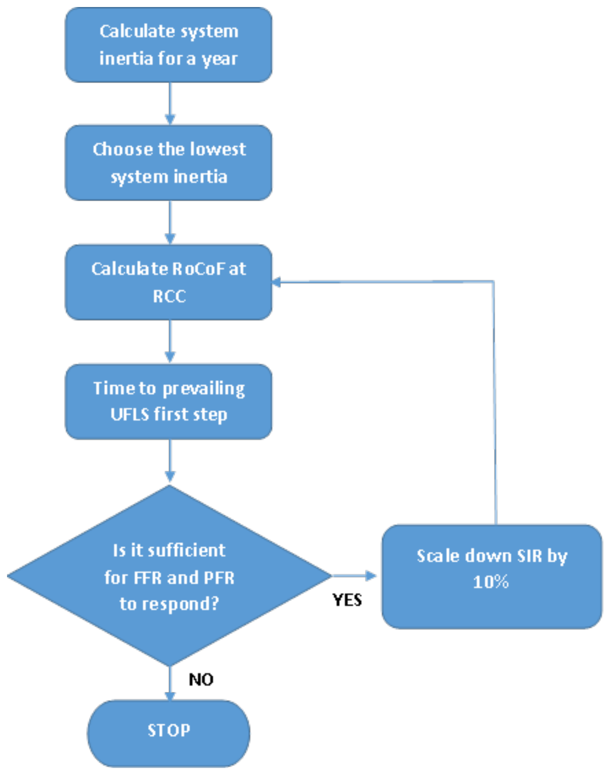
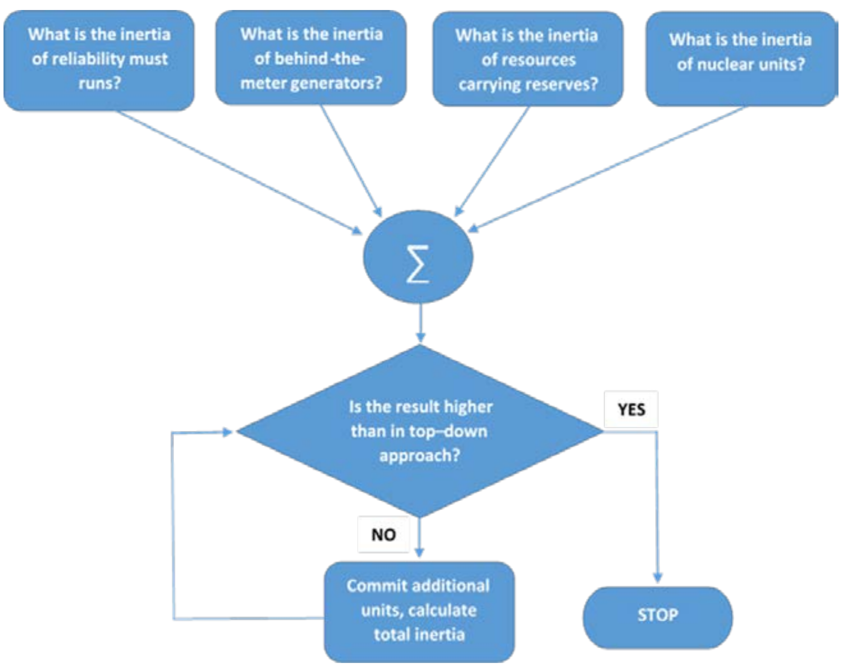


Figure 2: Top-down Approach to determine critical synchronous inertia

5. The system inertia value determined above is a **theoretical** top down approximation of critical inertia. It is possible that in reality there is always more synchronous generation online at any given time due to other considerations. In order to obtain a more accurate value, one can use bottom up approach. Start with minimum synchronous inertia that will always be online for a system. For example:
   i. Are there any reliability-must-run units (e.g. for voltage support or transmission reliability) that would need to be online in these conditions?
   ii. Are there any synchronous condensers or generators in synchronous condenser mode that would need to be online in these conditions
   iii. Are there any behind-the-meter industrial generators that are always online?
   iv. Are there nuclear units? Of those how many units could be on maintenance simultaneously during low inertia times?
   v. How many are synchronous generators online to provide required reserves, what are those generators (what are their typical inertia values)? Here it is important to consider if there are any physical limitations or regulatory restrictions on how much a single resource can or is allowed to contribute towards a reserve requirement. In ERCOT, for example, a

generator is not allowed (by protocols) to offer more than 20% of its high sustainable limit towards Responsive Reserve Service[3]. Calculate the total inertia contribution for all these "must run" units which need to be online to contribute to reliability, capacity or AS requirement.

6. Compare the inertia calculated in step 5 and the approximated critical inertia in step 4.
7. If Inertia from step 5 is higher or equal to the inertia in step 4, then the system will have sufficient synchronous inertia at all times, unless
   i. Any operations principles of the "must run" units change.
   ii. Reserve requirements decrease.
   iii. Contribution from a single resource towards any of the online reserve requirement changes.
   iv. New reserves are introduced or entry of new resources (not providing synchronous inertia) into Ancillary Services market becomes possible.
8. If inertia from step 5 is lower than one in step 4, then starting from the unit commitment and total "must-run" inertia value obtained in step 5 bring additional synchronous units online one by one, based on unit merit order. Stop once the total system inertia value is close to the critical value determined in step 4.



[3] This is because with 5% governor droop setting a generator is not able to provide more than 20% of its capacity in response to system frequency change of 0.6 Hz (i.e. from 60 to 59.4 Hz, with 0.1 Hz margin above first stage of UFLS).

Figure 2: Bottom-up Approach to verify minimum sufficient synchronous inertia determined via top-down approach

9. The result from step 8 can then be verified with dynamic simulations, using unit commitment from step 8 and simulating an RCC event. Since the above calculation does not take into account load damping and primary frequency response, it's possible that the actual, critical synchronous inertia value is slightly lower than this theoretical estimate. Note, however, that load damping and governor response do not significantly affect RoCoF in the first seconds of an event. There can be also additional concerns with low synchronous inertia apart from frequency events, e.g. voltage oscillations and stability issues due to insufficient synchronizing torque.

Once critical inertia value is identified, actual synchronous inertia of the system (Measure 1) has to be monitored against this value. However, is important to start planning ahead of time rather than waiting for synchronous inertia to reach critical value. For the systems that are nearing critical inertia value it would be practical to start forecasting future inertial conditions, see Appendix.

Commented [MJ2]: At the end of this document the Appendix will be attached with revised methodology (compared to ERSTF Final Report) on how to forecast future low inertia conditions.

As the synchronous inertia is approaching critical value, frequency control measures need to be revised and additional means of fast frequency support (e.g. from load resources, storage, synthetic inertia from wind turbines) put in place.

Note that fast frequency response may also be introduced to address other issues such as resource adequacy, need for flexibility and to improve energy market efficiency, i.e. to make generation resources available for energy production while allowing other resources, e.g. load or storage, provide frequency reserves. In this case, minimum sufficient synchronous inertia needs to be revised by repeating steps 1-9 and including fast frequency response characteristics into the analysis.

Case Study: Calculation of Critical inertia in ERCOT

This calculation example follows the same process as the sufficiency guideline above

1. Calculate system inertia for every hour in a year in MVA*seconds. Figure below shows box plots for system inertia in ERCOT.[4] Minimum inertia in each year and supporting data for the wind penetration record in each year are shown in the table blow.

[4] Note this values are somewhat higher than shown in the NERC ERSTF Framework Report. This is due to different accounting of inertia contribution from Private Use Networks (PUN). Private Use Network is an electric network connected to the ERCOT Transmission Grid that contains Load that is not directly metered by ERCOT (i.e., Load that is typically netted with internal generation). Previously PUN generation was only considered online if PUN net-production was above 5 MW, however, in reality, PUN generation can be online and producing power, while exporting 0 MW into ERCOT. In this situation PUN generation is still synchronously interconnected with ERCOT grid and will provide inertia during contingency events. After recognizing this PUN generators with gross-production above 5 MW were included in total system inertia calculation as shown in the box plots below.

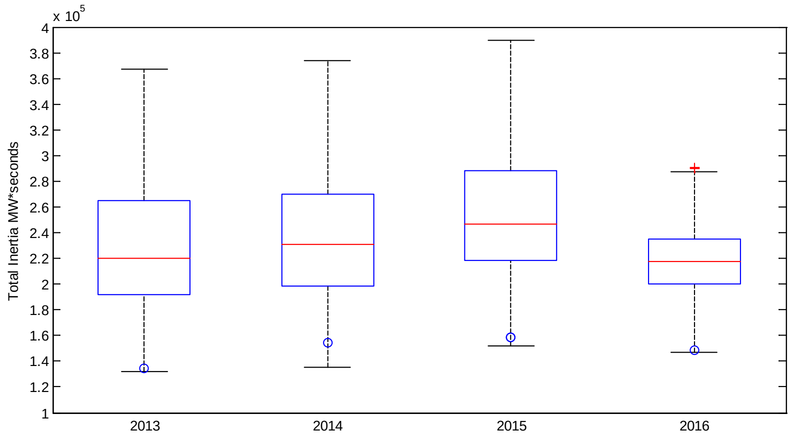


Fig. 5. Boxplot of the system inertia from 01/01/2013 to 3/31/2016

Table 3. Lowest inertia in different year (GW·s)

2013	2014	2015	2016
132	135	152	147

1.

Table 4. Wind generation power and load demand at the time of record of each year

	2013	2014	2015	2016
	3/9 3:15 am	11/3 2:28:56 am	12/20 3:05 am	3/23 1:10 am
Installed Capacity (P_{wind_inst}), MW	10,570	12,527	16,170	16,547
P_{wind}/P_{load}	35.8%	39.93%	44.71%	48.28%
P_{wind}, MW	8,773	9,882	13,058	13,154
P_{wind}/P_{wind_inst}	83%	78%	81%	79%
Net Load, (P_{load} - P_{wind}), MW	15,716	14,868	16,150	14,091
Inertia, MW*seconds	134,196	154,599	158,970	148,798
Installed Capacity (P_{wind_inst}), MW	10,570	12,527	16,170	16,547

2. Minimum system inertia for the past three years in ERCOT reached 132 GWs in 2013. Using the expression below it is possible to calculate Rate of Change of Frequency based on ERCOT's RCC which is loss of two nuclear units with total capacity of 2750 MW.

$$RoCoF = \Delta P_{MW}/(2*(KE_{min}-KE_{RCC}))*60 \quad [Hz/s]$$

At 132 GWs inertia, the RoCoF will be 0.69 Hz/s and it will take slightly over a second to get to the first stage of underfrequency load shedding at 59.3 Hz.

3. ERCOT has load resources with underfrequency relays providing up to 50% of Responsive Reserve Service requirement. These load resources will trip in 0.5 seconds after frequency reaches 59.7 Hz. With RoCoF as calculated above, 59.7 Hz will be reached in 0.43 seconds after the event, which means load resources will trip in about 0.93 seconds after an event, and system frequency will be at about 59.35 Hz at the time and therefore will be arrested before involuntarily underfrequency load shedding.
4. Gradually scaling down system inertia and performing same analysis as in the previous step shows that at about 105 GW s of inertia 59.7 Hz is reached at 0.35 seconds and 59.3 Hz is reached at 0.85 second therefore this inertia value can be considered theoretical critical inertia for ERCOT considering current frequency control practices.
5. Following bottom up approach described in the previous section, we need to establish if, theoretically, system inertia can fall below the critical value found in step 4 or is there always sufficient inertia online from the generation units that are always online:
   i. Currently there are no reliability must run units in ERCOT.
   ii. Private Use Networks (PUN), see Table 2 detailing min and max of their inertia contribution for the past 3 years, minimum in the past 3 years was 31.5 GW·s.

Table 2. Inertia contribution from PUN

Year	**Min inertia from PUN, GW·s**	**Max inertia from PUNs, GW·s**
2013	31.5	53.7
2014	48	52
2015	36	58

   iii. At least 3 nuclear units are normally online with total inertia of at least 18.4 GW·s.
   iv. NERC IFRO requirement is currently -381 MW/0.1 Hz. To ensure the IFRO is fulfilled ERCOT will procure sufficient amount of Responsive Reserve Service (RRS). Minimum RRS from generation requirement during low inertia hours in ERCOT is 1348 MW. According to ERCOT Nodal Protocols, there is 20% limit on how much capacity a single resource can offer towards RRS. Thus, 1348 MW will be distributed between generators with total installed capacity of at least 6740 MW, total MVA of these generators is assumed as 5650/0.9=7488 MVA. In ERCOT various generation types are qualified to provide RRS:
      - If all RRS is provided by CC units with H=4.97 seconds[5], the inertia contribution for generation resources providing RRS will be at least about 37 GW·s.
      - If 1348 MW is provided by smallest qualified for RRS coal or gas-steam units, then the inertia contribution for generation resources providing RRS will be about 22 GWs.
      - If RRS is provided by qualified hydro units in synchronous condenser mode (to its full capacity) and the rest is provided by qualified and participating gas steam units with the lowest inertia then the inertial contribution from RRS resources would be 20 GWs.

[5] In 2014 about 68% of generation RRS was provided from Combined Cycle (CC) generation, in ERCOT average CC has inertia constant of 4.97 seconds on 600 MVA base

Note that neither PUNs nor nuclear units are qualified to provide RRS in ERCOT. Therefore there is no double counting of these units in "must run" inertia calculation.

v. We can assume that at the worst case, Regulation Reserve are carried by the same units that are providing RRS and no additional unit commitment will be necessary to provide Regulation.

If ERCOT system has sufficient non-synchronous, renewable generation to serve system load, then nuclear units, PUNs and units providing RRS will be the only ones supplying synchronous inertia to the system. Based on the considerations above, this total synchronous inertia will always be 70-87 GW·s, unless PUNs significantly change their operating strategies, e.g. due to frequent negative energy prices at nighttime during winter/spring.

6. Theoretical critical inertia obtained in step 4 is 105 GWs,
7. "Must run" units will only provide about 70-87 GWs of inertia, which is less than critical sufficient inertia of 105 GWs.
8. Currently due to low gas prices Combine Cycle units are displacing Coal units in unit commitment. To provide 25 GWs of inertial response additional 9 CC units (600 MVA, H=4.97s) would be required online.
9. Dynamic studies conducted in 2014 also showed that when the inertia of the ERCOT system is less than 100 GW·s, loss of two largest units will cause voltage oscillations and voltage control issues in the Panhandle area.

Note, however, that currently Combined Cycle units are running more often and not turning offline during low load hours. Typical Combined Cycle in ERCOT has higher inertia contribution compared to the same MVA coal unit. This is why ERCOT's inertia is trending up in 2015-2016 even though renewable generation share keeps growing.

Example below shows how critical inertia is reduced with increasing frequency trigger for fast frequency response or shortening response time (from 30 cycles to 20 cycles). Note at low inertia values rate of change of frequency is faster and inclusion of load damping, equation (3), in frequency calculation becomes important.

30 cycle to trigger Load Resources or other Resources providing RRS in a similar manner			
Trigger freq., Hz	**Critical inertia, GWs**	**time to trigger freq., s**	**time to 59.3 Hz**
59.7	105	0.35	0.85
59.8	88	0.19	0.69
59.9	77	0.08	0.58
20 cycle to trigger Load Resources			
Trigger freq., Hz	**Critical inertia, GWs**	**time to trigger freq., s**	**time to 59.3 Hz**
59.7	75	0.23	0.53
59.8	63	0.12	0.45
59.9	55	0.05	0.38

Calculation of Critical inertia in WECC

WECC operates as set of island at certain times in a year. In this case each island's critical inertia needs to be monitored.

Commented [MJ3]: Can somebody contribute here describing the islands and how often the system is operating that way. What would be the largest N-2 contingency for each island?

Alberta Electric System Operator is studying islanded operation and inertia sufficiency in this conditions.

Are there any other areas that operate this way and would benefit from sufficiency evaluation.

Calculation of Critical inertia in EI

Should we study parts of EI system assuming only other parts are not contributing to system inertia and this way finding critical inertia for each area in isolation?

Commented [MJ4]: Could anyone elaborate this idea?

How should the issue of varying frequency throughout the system during an event be addressed?

Future projections of system inertia

This section will describe methodologies for projecting synchronous inertia conditions for the future years.

Monitoring and forecasting synchronous inertia in the day-ahead and real time

As the operation of conventional generation resources and the continuous growth of wind and solar generation bring more uncertainties to how the grid is operated, there emerges is a need to monitor system inertia in real-time and also to help operators to predict it for the near future. The system inertia will be added as key indicator for the system operating conditions alongside voltage and frequency.

Monitoring of synchronous inertia and frequency deviation based on Resource Contingency Criteria was recommended as Measure 5 by ERSTF.

ERCOT Tools to Monitor and Predict System Inertia

Inertia Monitoring Tool and Dashboard

In order to streamline monitoring and analysis of the system inertia as well as contribution by individual generation types, ERCOT staff set up various data points to calculate synchronous inertia once a minute[6] by resource type and system total.

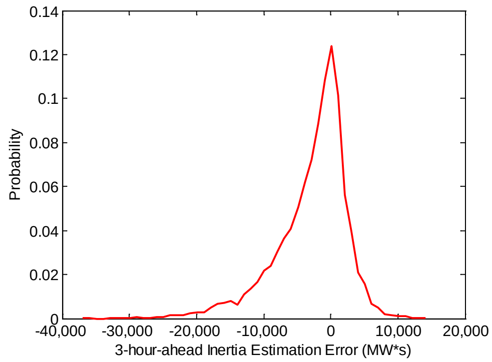
Additionally a real time inertia dashboard was experimentally set up to monitor the inertia in real-time as shown in Fig. 12. The dashboard also shows last 24 hours inertia contributions by generator type. Monitoring by type is done to enable more granular analysis of inertia trends.

[6] Currently being updated to calculate every 4 seconds to align with Measure 1 and 2 data collection process recommended by ERSWG

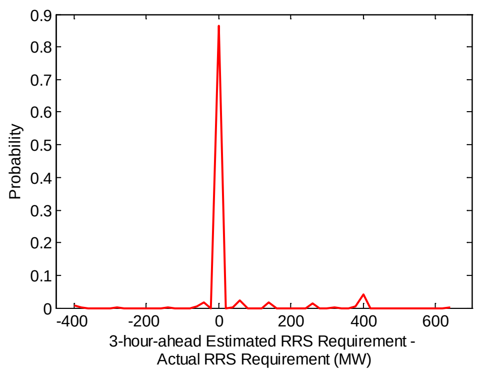
Fig. 6. A dashboard to monitor inertia in real-time

Inertia Prediction Tool

The system inertia can be predicted using the current operation plan (COP) information submitted by the generators to provide some foresight into what the actual condition will be. The probability distribution function of 3-hour-ahead inertia estimation error using COP data in 2015 is shown in Fig. 13 (a). This prediction will open up an opportunity for operators to evaluate the sufficiency of procured Responsive Reserves as well as recognize the risk for extremely low inertia condition ahead of time and prepare a mitigation plan if needed. The performance of 3-hour-ahead RRS estimation is evaluated in 2015, with 3.78% of time for under-estimation (3-hour-ahead RRS estimation is less than the actual RRS requirement) and 10.1% of time for over-estimation – see Fig. 13 (b). One example of under-estimation of the RRS requirement is depicted in Fig. 14. On Nov. 4 2015, the system lambda (the dot line) dropped below 10$/MWh in the earlier morning. In response to this, some generation units which submitted "online" status in COP ahead of time were eventually running offline in real time, which resulted in an under-estimation of the system inertia. When the energy price was recovered, the generation units came back online so that 3-hour-ahead estimation of the system inertia matched well with the actual system inertia after 6 am.



(a) error in 3-hour-ahead inertia estimation



(b) error in 3-hour RRS requirement estimation

Fig. 13. 3-hour-ahead estimation error of inertia and RRS requirement

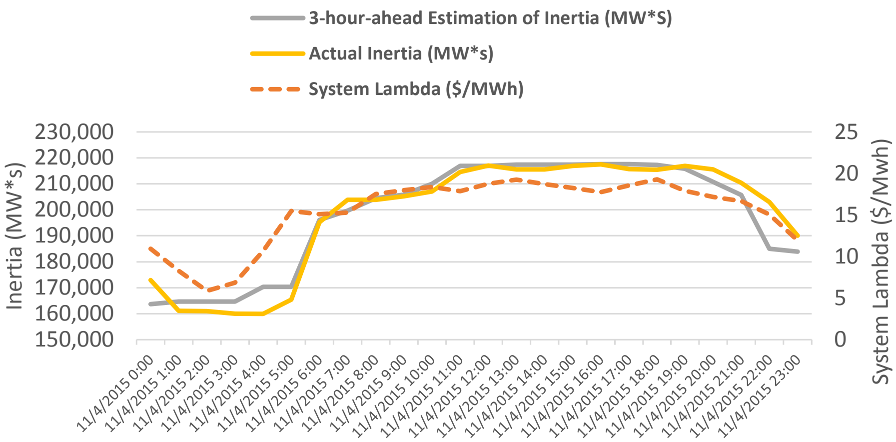


Fig. 14. System lambda and inertia on Nov. 4, 2015

Mitigation of Extremely Low System Inertia

There are multiple technical solutions to mitigate the impact of low system inertia:

- Bring online additional synchronous inertia as needed by committing additional units, committing different units that have higher inertia, and/or using synchronous condensers.
- Slow down rate of change of frequency by increasing rate of primary frequency response of the system in MW/s per Hz
- Slow down rate of change of frequency by increasing the speed of frequency response, i.e. add fast frequency response from load resources, storage, synthetic inertia from wind generation

These technical solutions can be implemented as described below and summarized in Table 6.

Bring online additional synchronous inertia

- Start-up more generation units

  If system inertia is low, system operator may choose to bring more synchronous generation units online and thus increase system inertia. One benefit of this approach is that it would only be implemented during conditions when insufficient inertia was otherwise committed on the system, and therefore it would not affect market solutions during other periods. The generating units, once started, will run at least at their minimum sustainable level, producing energy that is not needed otherwise. This may result in renewables curtailment and adverse effect on energy prices. The generators started up for inertia would need to be uplifted (i.e. compensated) for their startup costs and power production at minimum generation level. It would be important to consider the relative inertia provided by the different units that could be brought on line and their minimum generation levels, in order to get the maximum inertia for the cost. This will be only recommended when the system inertia falls below the critical inertia level, which causes a serious concern for reliability.

- Procure Inertia as a separate Ancillary Service product
  This mitigation measure will enable system operator to keep minimal synchronous inertia level online through market mechanism. Currently, inertia is provided by synchronous machines as the by-product of energy or ancillary service and no compensation has been offered for this service. Once historic analysis of system inertia will show that a system more frequently experiences extremely low inertia conditions, it could be more efficient to incentivize synchronous inertia service as Ancillary Service and to add minimum inertia constraint into Day-ahead Market clearing process. This may be the most efficient way to address low system inertia issue because it is implemented through market mechanism. On the other hand, it may require significant changes to a market design and structure.
- Include the need for inertia in the procurement of reserves
  For example in ERCOT, the current procurement of RRS takes into account the expected level of inertia of the system to determine the quantity of RRS to be procured and assumes a contribution to system inertia from the resources providing RRS. However, the RRS procurement could be modified so that the different contributions to inertia from the resources offering to provide RRS could be considered in determining which offers are selected to provide RRS. In this construct, the RRS procurement would solve both the need for RRS and inertia sufficiency.
- Install synchronous condensers
  Synchronous condenser is similar to synchronous generator but without a turbine, its main purpose is to provide dynamic reactive power support. Being a rotating machine, however, it can also contribute to total system synchronous inertia. This option may be expensive if used for inertial support alone, however recent studies for Panhandle region proposed synchronous condensers for voltage support. As one of long-term solutions, use of synchronous condensers for multiple purposes may prove to be more cost efficient. Regardless, the contribution to inertia from synchronous condensers that are installed for transmission system support should be included in the assessment of how much inertia is available.

Increase rate of primary frequency response

- Procure more responsive reserve service (RRS)
  As shown in Fig. 4, the need for RRS is increasing significantly during low inertia conditions. By procuring more RRS capacity spread over more units, we are trying to obtain a higher rate of response MW/s per Hz during severe under-frequency events. This mitigation measure is easy to implement since it can be accommodated by the existing procedures and framework. However, this option would be inefficient to some extent since large amount of RRS need to be reserved for the whole month but only used to hedge against a few hours when system inertia conditions are low. Additionally, if low inertia conditions are not predicted ahead of time and additional RRS needs to be procured in real time through Supplemental Ancillary Service Market (SASM), the price of RRS may be extremely high as well. During low system inertia hours, high RRS requirement will force more synchronous generation online, thus increasing system inertia and decreasing actual need for RRS simultaneously.

Commented [MJ5]: This is very ERCOT specific right now, will make it more general.

Add fast frequency response

- Incentivize/use fast frequency response from other technologies
  As was pointed out above, what is critically needed at low system inertia conditions is fast response to counteract high rate of change of frequency if the voltage oscillation is not a

problem. Fast frequency-responsive load resources, e.g. large industrial loads, heat pumps, industrial refrigerator loads, storage devices, can provide full response in a few hundred milliseconds to the under-frequency events. This type of response has been compensated within current market framework and could be more incentivized in the future by introducing a fast frequency response Ancillary Service. This is considered as one of the most viable solutions if it can attract a sufficient volume of participants.
Example below shows how critical inertia is reduced with increasing frequency trigger for fast frequency response or shortening response time (from 30 cycles to 20 cycles). Note at low inertia values rate of change of frequency is faster and inclusion of load damping, equation (3), in frequency calculation becomes important.

Commented [MJ6]: Need to add some discussion to this document showing dependency between added MW amount of fast frequency response and critical inertia.

30 cycle to trigger Load Resources or other Resources providing RRS in a similar manner			
Trigger freq., Hz	**Critical inertia, GWs**	**time to trigger freq., s**	**time to 59.3 Hz**
59.7	105	0.35	0.85
59.8	88	0.19	0.69
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20 cycle to trigger Load Resources			
Trigger freq., Hz	**Critical inertia, GWs**	**time to trigger freq., s**	**time to 59.3 Hz**
59.7	75	0.23	0.53
59.8	63	0.12	0.45
59.9	55	0.05	0.38

- Synthetic inertial response from wind generation
  Another example of fast frequency response is synthetic inertia provision from wind generation resources (type-3/4). When wind turbine plant controller senses system frequency, it extracts kinetic energy of rotating mass of wind turbine, which is seen from the grid as an increase in active power injection. The effectiveness of the response and recovery of wind generation resource to its pre-disturbance state depends on operating conditions of a wind generation resource. Therefore this type of fast frequency response requires careful centralized coordination to enable reliable system operation. While synthetic inertial response capability is already included as a part of interconnection requirement in Hydro Quebec, this technique has not been commercially utilized at large scale.

Table 6. Options to mitigate impact of low system inertia

	Time Horizon	**Impact**	**Cost of Implementation**	**Effectiveness**
RUC more synchronous generators	Operation horizon	Increase inertia, wind curtailment, adverse effect on real-time market prices	Medium	Medium

Procure Inertia as an Ancillary Service	Operation horizon	Introduce new AS, increase inertia, wind curtailment	High	Medium
Install synchronous condensers	Long-term planning horizon	Increase inertia, additional dynamic voltage support	High	High
Increase monthly RRS requirement	Operation Planning horizon	Increase reserve and rate of response, wind curtailment	Medium	High
Fast Frequency Response (Storage, Load Resources etc.)	Operation horizon	Introduce new AS, increase reserve	Low-Medium	High
Synthetic Inertia	Operation horizon	Introduce new AS or protocol requirement, requires implementation of centralized control	Low-Medium	Medium