NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Generator Governor Frequency Response Advisory

## Webinar Questions and Answers

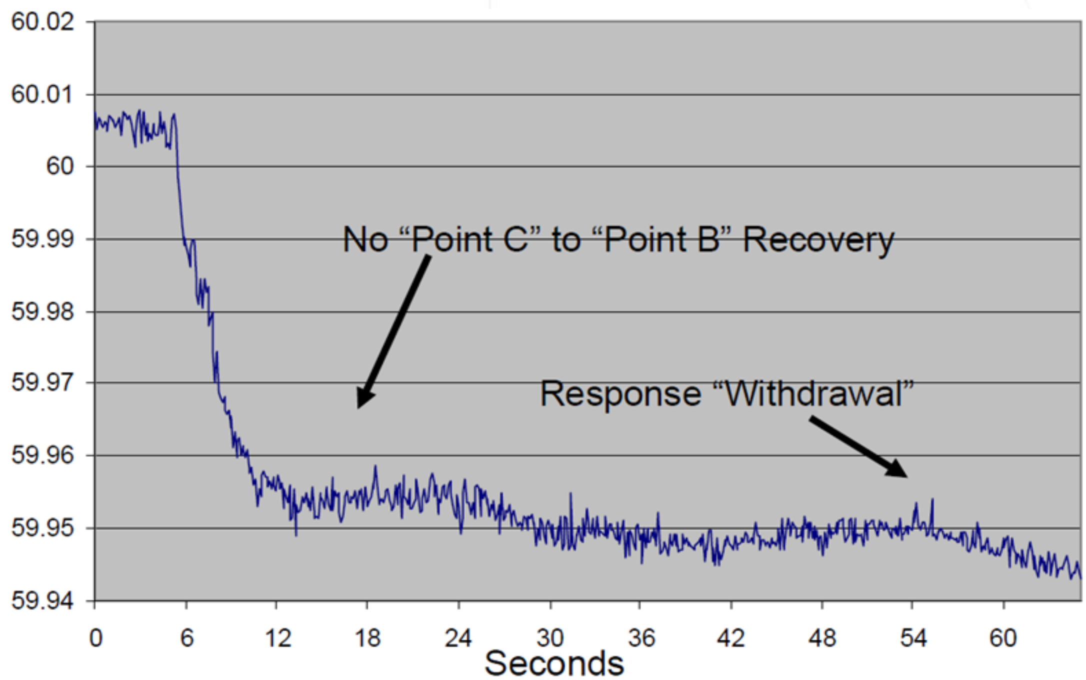
April 7, 2015

1. ***I thought the recent NERC review on system performance reported no decline in frequency response over the last five years?***

   This is correct. However, the Eastern Interconnection frequency profile is challenged with a "Lazy L" indicative of lack of primary frequency response followed by subsequent withdraw of MW response. Further, it has been discovered the vast majority of the gas turbine fleet is not frequency responsive due to a missing algorithm when operating in MW set point control. In addition, in many conventional steam plants dead band exceed the maximum 36 mHz dead band and response is squelched and not sustained.

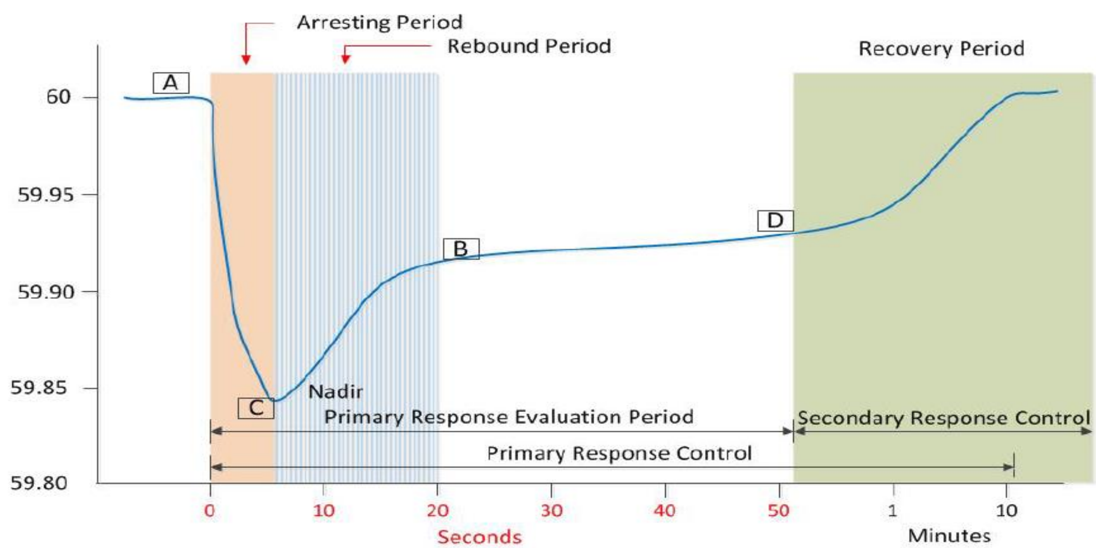
2. ***Describe the Lazy L. What is it?***

   The term "Lazy L" is a reference to a frequency profile typical of the Eastern Interconnection and describes the event frequency profile after a sudden loss of generation. Frequency declines to a new lower equilibrium and remains flat for 10 to 30 seconds and then reduces further due to withdraw of primary frequency response from generation. Below is an illustration of the Eastern Interconnection "Lazy L" profile after a sudden loss of generation.



***3. Could you please have discussion on first few cycles or millisecond before point C?***

Prior to point C or the Nadir, the rate of frequency decline is a function of the inertia of the Interconnection and arrested by primary frequency response. In addition to primary frequency response from generation, load dampening contributes to the overall Interconnection frequency response as soon as frequency changes. This response is automatic and is referred to as the Arresting Period. As shown by the graph, the rate of the change of frequency decreases as primary frequency response is delivered. When primary frequency response and load dampening equals the loss of generation, frequency is arrested at Point C.




***4. I believe slide 10 and 11 seem to contradict each other***

Slides 10 and 11 are two different measurements of frequency response. Slide 10 is the average annual historical measurement (MW/ .1 Hz) of primary frequency response in the Eastern Interconnection based on selected events. Slide 11 is an illustration of the Eastern Interconnection "Lazy L" profile typically from a sudden loss of generation.

***5. Do you know the reason of response withdrawal?***

The withdrawal is a result of a MW reduction from the responding generators not sustaining an initial positive MW response. This most likely is caused by outer loop controls "squelching the response", lack of coordination with boiler or plant controls, mode of operation of generator, dead band setting, or other characteristics of the resource providing frequency response.

***6. Are there any system concerns with generator/steam turbine set that are operated by pressure control; throttle is wide open and load controlled by the droop of the steam pressure source?***

Yes, under this operating mode the generator cannot provide any primary frequency response for low frequency deviations. With the turbine valves operating wide open, when a frequency decline occurs; there is no room for the valves to open, preventing frequency response. Boiler controls alone often take longer than the period of primary frequency response to respond.

7. ***Our principal concern is ensuring that our MOD-027 inputs on the subject are correct, so that the TPs model produces realistic predictions. Our understanding is that we do not need to test generation units and should simply state that applicable unit is not responsive to both over and under frequency excursion events (ref. MOD-027-1 Att. 1 Row 7). For units that cannot react to a grid frequency drop when at full load (CTGs on firing temperature control, and STGs running VWO), regardless of the circumstance that such units can in fact respond to over-frequency events. Is this correct?***

   We disagree this should be your principal concern. We encourage all generation subject the NERC Advisory verify the generator is frequency responsive between Pmin and Pmax with settings not to exceed those provided in the NERC Advisory. As stated when units are at PMAX, there is not an expectation of the generator to be frequency responsive for frequency low events but do request support for frequency high events. Frequency response as discussed is essential for the Reliability of the Interconnection and System Restoration. The industry is encouraged to be supportive to minimize future requirements.

8. ***Does NERC plan to issue guidance concerning how to comply with BAL-003-1?***

   NERC hosted a webinar providing guidance on BAL-003-1 on September 12, 2014. See Project 2007-12 Frequency Response webinar information at the following:

   http://www.nerc.com/pa/Stand/Pages/Webinars.aspx

9. ***Is there a slide about large solar generation in west***

   No we did not discuss the large solar penetration in the West Interconnection. This presentation was intended to bring to the industry attention the purpose of the NERC Advisory and identify some of the known issues discovered, such as governor dead bands exceeding 36 mHz, Droop Settings exceeding 5% and outer loop controls prohibiting or squelching primary frequency response. As discussed primary frequency response is critical to the Reliability of the Interconnection and the addition of renewable to the generation mix further amplifies the need for all resources to address frequency response issues to ensure the reliability of the Interconnections. Please be aware there is a BA, ERCOT, which requires solar to provide primary frequency response.

10. ***What is the unit of droop? Say pu freq. div/pu power or pu freq div/pu gate***

    Droop is unit less value expressed in %. It represents 100% of unit movement for assigned droop percent change in nominal frequency (60 Hz). For example a generator with 5% droop setting should be able to be at max or min MW output for a 5% change in frequency from 60 Hz.

11. ***You didn't clearly articulate why the GTs went up 3MW a piece. I think they go up (at first) because the speed sensor on the GTs notices that they have dropped RPM (because the frequency was low). Is this correct?***

    Yes. In the examples provided on Slide 16 and 17, the turbines increased their MW output due to dead band and droop settings of the turbine governor. An input into the turbine governor's control is speed (RPM), which determines the frequency response and resulting action to the control valve(s) increasing fuel, steam or water resulting in additional MW output in response to the declining frequency.

12. ***If the algorithm is missing, why not issue something stronger than an alert? What about having the Regions conduct spot checks to ensure compliance?***

    As stated, the frequency response algorithm is missing in the majority of the gas turbine fleet when operating in MW Set Point Control. The NERC OC approved the Advisory, as an initial step to inform the industry of the identified issues and requests its support in self correcting dead band, droops and outer loop control to allow the generation fleet to be responsive between Pmin and Pmax as applicable. NERC expects the industry to support the Advisory. Additional steps can be taken if determined are needed. Regions are not precluded from taking additional actions such as providing requirements as ERCOT has done.

13. ***Is there any requirement to keep the droop setting at 5% during Restoration Process? Can we set at least one black start unit at zero droop?***

    The Advisory focus is on normal operations. There is not a requirement to keep the droop setting at 5% during System Restoration. It is acceptable to have a black start unit with zero droop. During restoration, it may be required to modify droop settings to provide adequate frequency response to support the load restoration process. Typically, black start units have the ability to operate in isochronous mode which is 0% droop and 0 mHz/RPM dead band.

    The reference made to the importance of frequency response during System Restoration during the webinar is relative to the fact that in most system restoration plans, Balancing Authorities, Transmission Operators and Reliability Coordinators expects the restored generation to be frequency responsive to maintain frequency stability while restoring load and interconnecting back to the restored grid. During system restoration large frequency oscillations could result in damage to the generators and transmission equipment. Primary frequency response reduces the frequency oscillations.

14. ***Slide #19- the positive response on the 175 MW turbine was possible due to the unit not being at full load. Under a market structure, units that do not clear reserves and/or regulation often sit at full load. Units at full load often are at 100% valve opening which does not allow for additional MW generation for frequency response.***

    This is correct. When generation is dispatched in a market or a part of vertically integrated utility to Pmax, there is only an expectation to provide response to frequency high events, by reducing generation.

    However, many of the frequency low events occur when most or a majority of the generation is less than Pmax. It has been discovered the vast majority of the gas turbine fleet is not frequency responsive due to a missing algorithm when operating in MW set point control. In addition, in many conventional steam plants dead band exceed the maximum 36 mHz dead band and response is squelched and not sustained.

15. ***When looking at the frequency data, are you looking at unit loss events only or are you looking at all frequency deviations including ramps? In the Eastern interconnection, frequency is constantly changing, many times a day .036 Hz or more. This is a concern with the recommendation of moving to a .019 Hz deadband.***

The recommendation is not to exceed .036 Hz. You are correct frequency is changing many times a day due to the imbalance of generation and load. The frequency oscillations are also indicative of lack of primary frequency response. As primary frequency response is improved and dead bands are lowered, Interconnection frequency oscillations are expected to be reduced.

16. ***We have found P1/PT schemes in Outer MW Loop in the DCS that overrode the Governor Response even though MW Frequency Bias in the Outer Loop existed. This P1/PT scheme had to be removed.***

    The outer loop control frequency bias algorithm droop and dead band settings must match the droop and dead band settings of the generators. All GOs are encouraged to look at dead bands, droop setting and outer loop controls that may prevent or squelch primary frequency response and take actions to correct.

17. ***We have also found where AGC from dispatching, not having Frequency Bias, would try to pulse the unit down immediately, opposite from the primary governor response. This presentation doesn't have any discussion regarding the AGC aspects that can inhibit response.***

    Correct. This is a very important issue that needs to be addressed. BAs that dispatch generation via pulse signal needs to include the frequency response algorithm to prevent squelching from the AGC pulse controls. Please work with your BA to coordinate proper adjustments to the frequency response model in their individual generator AGC algorithm.

    Further, there are a number of variables constantly changing within the system, such as interchange schedules, actual interchange, dispatch levels of resources, and load. The Frequency Bias component of a BA's ACE is typically relatively small in comparison to the other variables. It is conceivable these other factors can mask the frequency bias component of ACE. The end result could correctly provide AGC signals in a contrary direction to frequency. When a unit is frequency responsive, it will add the frequency response to the decline MWs resulting in increased MWs during this decline.

18. ***NERC Balancing and Frequency Control technical paper from 1/26/2011, states there is a new tool to receive e-mail notifications of frequency excursions that would be candidates for calculating responses (page 22). Is that tool available?***

    No. The tool referenced in the technical paper is currently not available. However, the NERC RS is working on the development of such tool to provide a notification of frequency events in near real time the industry can subscribe to.

    Additionally, CERTS produces a report of candidate events and is posted on the NERC Resources Subcommittee website typically within 15 days upon the conclusion of a month. These events are then reviewed by members of the NERC RS to be analyzed by BA to determine compliance for BAL-003-1.

19. ***Why is the primary freq response worse when units are less than PMax - wouldn't that mean there was more headroom?***

    Correct. This supports the issue the vast majority of the gas turbine fleet is not frequency responsive due to a missing algorithm when operating in MW set point control. In addition,many conventional steam plants dead band exceed the maximum 36 mHz dead band and response is squelched and not sustained. When system loads are less the load contribution is lessened as result.

***20. On our 2X1 site, we have 2 CTs which operate with linear droop. The steam unit has no droop which operates in load control or pressure control modes. Are you saying we need to have droop control on the steamer in this application? We had assistance from OEM on answering the NERC advisory and these are their responses.***

No. We are not expecting primary frequency response from the steam turbine of a combined cycle facility on low frequency events in the primary frequency response time frame. However, as the CT turbines MW increases and after long enough duration, the steam turbine will provide additional MWs.

If CT governor's droops are set for 4%, this will yield a plant droop response of little more than 5% which is acceptable, even though little or no primary response will be provided from the steam turbine unit.

***21. How to do find know if our droop controller takes us out of AGC, if it actually does?***

Some GOs report the plant DCS controls take the unit out of AGC or MW set point control when frequency response is required. The GOs are then having to call the BAs to inquire if the frequency event is over and request to go back in AGC mode or MW set point control. If this is occurring this should be apparent to your plant operators. Energy Management Systems that we are familiar with have an alarm input from the plant controls alerting the Balancing Authority Operator.

***22. Does a properly tuned GE power system stabilizer provide frequency response?***

No. PSSs add damping to the rotor oscillations of the synchronous machine by controlling its excitation. The disturbances occurring in a power system induce electromechanical oscillations of the electrical generators. These oscillations, also called power swings, must be effectively damped to maintain the system stability. To the extent that these oscillations exist, the PSS dampen the generator's voltage oscillations.

***23. If this is something that GOs should provide, why is the relevant standard, BAL-003, applicable to BAs not GOs?***

Yes. You are correct GOs should provide primary frequency response. The NERC Advisory and the current initiatives are directed to identify and correct issues relative to generators to provide primary frequency response.

The applicability is determined by the NERC Functional Model. The responsibility of providing primary frequency response is assigned to the BA. In the new BAL-003 Standard, the BA's responsibility is to assure that there is enough frequency response to meet or exceed their Frequency Response Obligation. Only the BA knows the dispatch of resources capable of providing frequency response, their current operating status, and can determine if adequate frequency response exists to meet or exceed it FRO.

***24. Is contact information available for participating vendors?***

Yes the information will provided with the Webinar presentation.

***25. Some slides are marked NPCC confidential. Is this true for a global NERC presentation?***

The confidential statements were inadvertently placed on two slides in the presentation. The presentation has been updated to remove the confidential references.

26. ***What is the process to contact the NERC Resource Subcommittee?***

    The members of the NERC RS can be contacted via email at Balancing@nerc.com

27. ***Have you studies any slow frequency declines as opposed to the step changes that typically have*** been reviewed in the past?

    Yes. This is typically caused by a run back in generation over a time frame of seconds to minutes, most often followed by a subsequent trip of a generator(s). These events are not typically selected for BA and subsequent GO evaluation because of the complexity of the event and typical longer duration.

28. ***Are the TOPs willing to provide the system Hz signal to the GOPs?***

    Contact your TOP if necessary and inquire. However, most if not all generators have a measurement and indication of speed (RPM) which is equivalent to frequency with a simple mathematical conversion.

    The equation is as follows: Frequency (Hz) = ½ X (# of poles) X (RPM/60). It is important to realize that speed input into turbine governor controls must be locally measured.

29. ***Will generator operators be required to operate at some level less than full load to assure the ability to react to frequency transients?***

    This is not anticipated at this time. The focus of the NERC Advisory is highlight the issue regarding the gas turbine fleet and conventional steam plants that are not frequency responsive due to improper dead band and droop settings and/ or outer loop controls prohibiting primary frequency response under normal conditions.

    BAs under BAL-003-1 will have the requirement to meet a minimum Frequency Response Obligation. It is hoped that this Advisory will raise an awareness of the issues such that most, if not all resources, are capable of providing frequency response. It would be the responsibility of the BAs to assure that those resources are operated in a mode and range to meet their FRO. For example, all units in a BA may be capable of providing frequency response, but only some may be needed to have headroom to meet the FRO, with the rest available to go to PMax.

30. ***In a cogeneration plant, the steam turbine on pressure control and pressure is maintained, steam flow varies. The combustion turbines provide the frequency response, but the steam turbine doesn't. How does one determine the max droop setting for the steam turbine?***

    According to most turbine OEMs, CT's droop settings are 4% and the steam turbine is 5%. However, we are not expecting primary frequency from the steam turbine of a combined cycle plant due to the operating mode of the steam turbine but it will occur if the event is sustained for a long enough period.

31. ***When simulating system frequency response, are you primarily monitoring frequency at transmission system buses or the speed of the machines?***

    For synchronously connected generators, the speed of the prime mover is the same relative to the grid frequency.

The equation is as follows: Frequency (Hz) = ½ X (# of poles) X (RPM/60). It is important to realize that speed input into turbine governor controls must be locally measured.

32. ***What was the primary reason for MW Set Point control initially***

    The understood primary reason simply was to provide Balancing Authorities and Generators with another form of control of the generation output.

33. ***The advisory says dead bands do not exceed +/- 36 mHz. Shouldn't that equate to a maximum 72 mHz instead of maximum 36 mHz dead band?***

    No. The range would be 72 mHz. The maximum dead band setting should not exceed 36 mHz.

34. ***With the increases in renewable generation and its lack of droop response, how will the proper mix of generation be developed?***

    Some BAs, such as ERCOT, are requiring renewable generation to be frequency responsive. This presentation was intended to bring to the industry attention the purpose of the NERC Advisory and identify some of the known issues discovered, such as governor dead bands exceeding 36 mHz, Droop Settings exceeding 5% and outer loop controls prohibiting or squelching primary frequency response. As discussed primary frequency response is critical to the Reliability of the Interconnection and the addition of renewable generation to the generation mix, further amplifies the need for all resources to address frequency response issues to ensure the Reliability of the Interconnections.

35. ***While individual units may not be required to provide frequency response at all times, isn't it true that entities must provide FR in accordance with BAL-003-1?***

    BAL-003-1 establishes a minimum Frequency Response Obligation or FRO on the Balancing Authority. In the new BAL-003 Standard, BAs responsibility is to assure that there is enough frequency response to meet or exceed their Frequency Response Obligation. Only the BA would know the dispatch of those resources capable of providing frequency response, their current operating status, and determine adequate frequency response exists.

36. ***Any special treatment on nuclear units?***

    Nuclear units are exempt from the NERC Advisory.

37. ***What is expectation of older steam units with Hyd/mechanical turbine controls but has the front end DCS droop control?***

    The desired expectation is to provide primary frequency response within the limitations of the mechanical governor same as other conventional steam generation. The hydraulic mechanical turbine controls are capable of providing excellent primary frequency response. If such a generator is found not to be responsive, it is typically related to plant DCS outer loop control settings or worn mechanical parts of the mechanical governors. The typical inherent dead band with this type of controller should be less than 36 mHz if properly maintained.

38. ***For a combined cycle plant, is the response expected to come from all of the units individually? What happens when two units ate at PMax and only one unit has room to respond?***

Correct primary frequency response would come from individual units that are between Pmin and Pmax. Ideally load would be distributed evenly among CTs. This would result in an equivalent 5% droop response from the facility.

39. ***Is a +/- 50 mHz a typical "old" standard?***

    NERC is not aware of this referenced value in any historical standard. The recommended maximum dead band of 36 mHz has long been documented in former NERC Documents, IEEE and EPRI publications.

40. ***Averagely how long does it take for the governor response withdrawal to completely reset to its scheduled set point?***

    In regards to generator outer loop controls, primary frequency response can be withdrawn within a couple of seconds to a minute depending on the generator control loop. Primary frequency response should be delivered from a generator until the frequency is restored within the dead bands of the governor. The average times that frequency is restored back within requested dead band would be in the range of 1 to 5 minutes depending on the Interconnection. (See Slide 7)

41. ***Where do i access this advisory and what is it called***

    The NERC Advisory can be found at the following link Generator Governor Frequency Response Advisory

42. ***What is the recommended frequency sampling rate to assess frequency response?***

    Frequency response is observed in typical EMS scan times between 2 and 6 seconds.

43. ***Generator testing is typically performed on a 5 year basis. Can the governor control updates be incorporated, but not tested until a normal testing schedule?***

    We are respectfully requesting the gas turbine generators determine and address the identified missing algorithm in the next planned scheduled outage (Fall 2015/Spring 2016). Additionally, conventional steam plants should evaluate dead band, droop and outer loop controls and make changes to enable primary frequency response within the limitations of the plant. Model data should be updated any time a change is made generator primary frequency response.

44. ***For large supercritical plant, is it a good solution to increase the droop dead band above the 36mHZ in case of frequency fluctuations in the grid?***

    No. Ideally, as frequency response is improved in the various Interconnections, oscillations in the frequency should be reduced.

45. ***What is the underlying cause of the generators not being programmed to provide primary frequency response? How could the industry get to this place? Were the programming problems more likely to occur in generators that are independently owned, versus those owned by a vertically integrated utility?***

    We are not aware of a single underlying cause unless to generally say the lack knowledge and/ or communications between entities. The frequency response initiative is aimed of increasing knowledge and as issues are identified asking OEMs, Architect and Engineering Firms, and Industry, etc to address. We have not determined the outer loop controls (programming) to be discriminating to either independently owned generation, versus those owned by a vertically integrated utility.

46. ***Does the lack of frequency response in spring and fall consider that there is perhaps less inertia on the system (fewer synchronous generators) and more asynchronous generation (wind and solar) connected?***

    Lack of primary frequency response from generation and load will result in a greater frequency change. The effect of renewable generation and the mix will impact the interconnection profiles, this further adds to the importance to address all the non frequency responsive generation in order for the Transmission Planner, Balancing Authorities and various other technical groups to make informed decisions. Some BAs, such as ERCOT, are requiring renewables to be frequency responsive.

47. ***Since the "Frame" designation was typically used during this discussion, since this term is specific to a certain turbine manufacturer, does this mean the control algorithm issue is confined to this manufacturer?***

    No. Incorrectly the "Frame" designation was used and as correctly stated it refers to certain turbine manufacturer. However, the non responsive issue on the gas turbine fleet is not related to just that manufacturer.

    The issue of the missing algorithm and the need for coordination of outer control loops exists in equipment most often not provided by the turbine OEM.

48. ***Any thoughts about gas supply issues? What if the pipe is close to minimum pressure requirement of turbine. If the governor opens up the gas valve it could trip the generator too. Have we studied done joint studies with the gas side? There are few gas lines that serve alot of MWs.***

    The amount of MW frequency response expected is minimal in relation to the total plant output. Typically, the response is less than 2% of the total capability of the generation unit and short in duration. As a result minimal changes are expected relative to gas pressure on gas pipeline infrastructure.

    If supply issues relative to the turbine exist, the reliability of the plant is the highest priority.