Potential New Ancillary Services: Developments of Interest to Generators

Brendan Kirby – www.consultkirby.com – kirbybj@ieee.org

Introduction

The number of potential ancillary services being seriously considered is increasing. Generators can potentially be paid for providing these services so it is in their interest to understand what is required to provide the services and the reasons they are being established. Alternatively, some new requirements may be established as conditions of interconnection without explicit payment. Here too an understanding of the power system need may help generators engage in the process establishing reliability rules and potential market structures. New services are being considered for inertia, governor response, and following (ramping). The increase in wind and solar generation is partly responsible for the increased interest in these services but so is changing technology which is allowing unconventional resources to provide responses that were previously exclusively the domain of conventional generators. Wind and storage can provide synthetic inertia. Some demand response can provide response between inertia and governor response. The Electric Reliability Council of Texas (ERCOT) is actively considering inertia and governor response requirements but is not currently seeking a following service. Both the California Independent System Operator (CAISO) and the Midcontinent Independent System Operator (MISO) are investigating following as a paid service. The Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) are both actively investigating all of these services and methods to best provide them.

Generator owners should always consider their options in supplying energy and the existing ancillary services (regulation, spinning reserve, and non-spin) to find the most profitable mix each hour. As markets for frequency response and ramping develop, generator owners should evaluate these options as well.

Standards Gaps

Balancing generation and load is required across the entire time spectrum from cycles to years under normal conditions and when contingencies occur. Power system planners and operators expend a great deal of effort to meet this basic reliability requirement in the most economical way. FERC, NERC, and the Regional Reliability Councils have established mandatory balancing standards covering specific time frames and under specific conditions. Ancillary Services have been defined to establish the resource characteristics needed to meet the standards requirements. Markets have been developed in many areas to obtain these ancillary services at the lowest cost.[1] NERC standards do not explicitly cover the full time spectrum, however. Historically this has not been necessary because of the inherent characteristics of the incumbent technologies, mostly large synchronous generators. As technologies change, however, gaps in standards coverage can result in reliability concerns. New standards and ancillary services may be required to explicitly address these gaps.

Response to a major generation outage (a contingency) provides a good example of how reliability was served and how standards gaps might arise. When a 1,000 MW generator trips off line there is an immediate generation/load imbalance with load exceeding generation by 1,000 MW. This results in all the synchronized generators throughout the interconnection slowing down and frequency dropping below 60 Hz as shown in Figure 1. The interconnection would collapse instantaneously were it not for the inertia of the generators and motor loads. Inertia cannot support frequency but it does slow the frequency decline.[2] As frequency drops and generators slow down the energy stored in the rotating mass of the turbine-generators is delivered to the power system. Next, other generators increase their output to make up for the generation that was lost and to reestablish the generation/load balance.[3] Generator governor response is first with generators themselves detecting the power system frequency drop and autonomously increasing their output. The power system operator also detects both the generator failure and the frequency drop and directs generators that were kept in reserve to increase their output. Once reserve generation has replaced the full 1,000 MW that was lost when the failed generator tripped the load and generation are again in balance and the power system 60 Hz frequency is restored. Normal economic operations resume when energy markets adjust supply to relieve the reserve generators, allowing them to return to reserve status in anticipation of the next contingency event.

NERC reliability standards cover part of this process. The rest is just as necessary but historically it occurred due to the inherent characteristics of the generators used. The only explicit contingency response balancing requirement was NERC's BAL-002 Disturbance Control Standard (DCS) which requires each Balancing Authority (BA) or

---

[1] Vertically integrated utilities meet the same NERC standards and typically use a central planning process to economically optimize the selection of resources in non-market areas with essentially the same optimization as obtained in market areas. This paper mainly discusses market areas because the rules, prices, and results are more transparent but the discussion and conclusions apply to both market and non-market areas.
[2] Inertia also slows frequency restoration when generation increases (or load drops) but that is not usually a reliability concern.
[3] Demand response can also provide contingency reserves. The initial discussion is limited to generators for simplicity.

Reserve Sharing Group to restore its generation/load balance within 15 minutes of having a major contingency. It also requires each BA to have enough reserves available to cover the largest expected contingency. Regional Reliability Councils determine how much of the contingency reserve must be spinning. There are also requirements for reporting on governor characteristics and for verifying generator models but there is no specific requirements on response speed or accuracy other than DCS.

Reliability was maintained without detailed requirements covering the time frame shown in Figure 1 because the large synchronous generators that dominated power production inherently have enough inertia. Similarly, large generators do not respond instantaneously so restoring the generation/load balance within the required DCS time could only be met if the spinning reserve resources began ramping up as quickly as possible. Lastly, good utility practice dictated having functional governors active on all generators. Essentially a single 15 minute (previously 10 minute) balancing requirement was sufficient to obtain the required reliability response over the full time spectrum from cycles to hours.

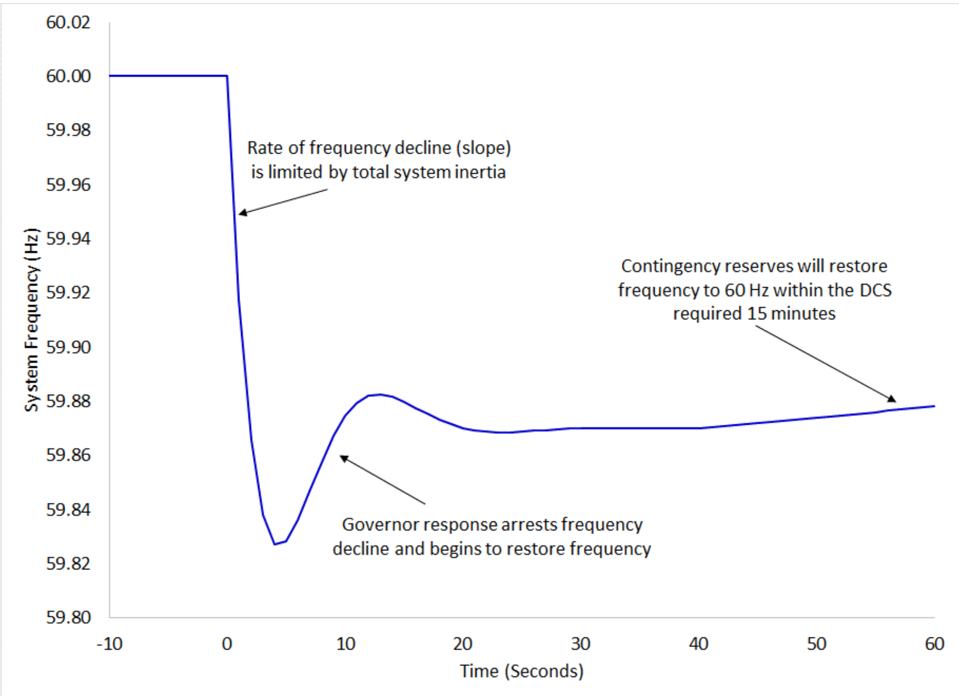

Figure 1 Typical interconnection frequency response to a major contingency.

Figure 2 shows the balancing services that provide the contingency response required in our example. Explicitly defined ancillary services are shown in blue. Potential new ancillary services are shown in red. Inertia is inherently provided by all of the generators so it was not necessary to define it as a required ancillary service. Governor response too was assumed to be amply provided by generators through good utility practice.

Spinning and non-spinning reserves are services that have been explicitly defined because there are economic costs for the owners that hold generation capacity back from supplying energy to make it available as contingency reserve. Note that the spinning reserve line is partly dashed. This is because while spinning reserve is defined as fully responsive within ten minutes the exact response before ten minutes, though required, is not rigorously defined. This is because different generation technologies and even different generators of the same technology often have very different short-term response characteristics. In order for a large thermal generator to provide its full spinning reserve response within ten minutes it must respond as quickly as possible but establishing overly strict requirements would only eliminate some generators from the available pool of spinning reserve resources. In one sense there is no point in specifying specific response requirements when a generator is doing the best that it can.

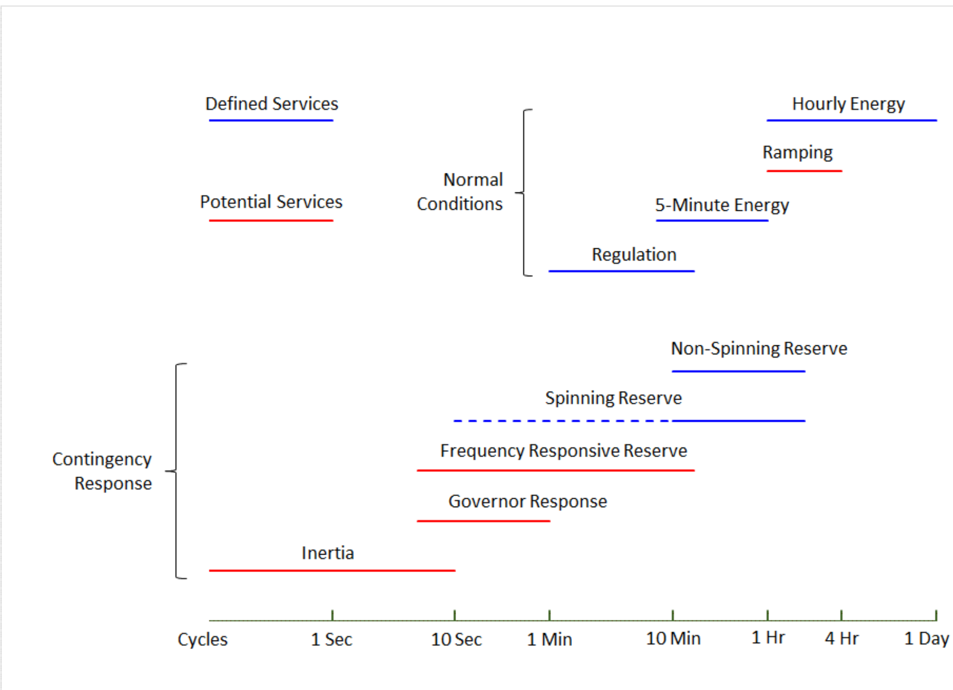

Figure 2 The power system must be balanced over the full time spectrum from cycles to days but defined balancing services do not yet cover the full range.

Unfortunately reliability response in at least part of the "unspecified" area below ten minutes in Figure 2 has declined since at least 1994. Figure 3 shows the mean frequency response of the eastern interconnection.[4] (Ingleson and Allen, 2010 and NERC, 2014b) It measures the effectiveness of governors in arresting the frequency decline after a major contingency. The metric compares the frequency that the interconnection settles to after a major outage, and before contingency reserves are

[4] Frequency response is also a concern in ERCOT and WECC but the historic downward trend is not as pronounced as in the east.

able to respond (~30 seconds after a large generator trips), versus the size of the contingency in MW.[5] Frequency response is measured in MW / 0.1 Hz:

Frequency Response = Generator Loss (MW) / Frequency Drop (0.1 Hz)

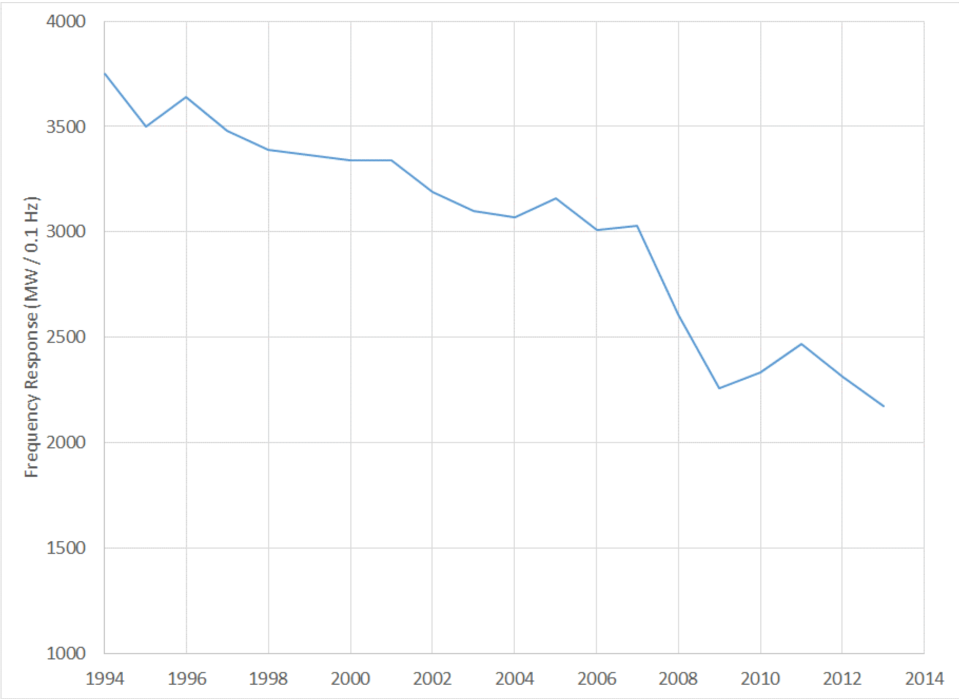

Figure 3 Frequency response of the eastern interconnection has been declining since at least 1994.[6]

As part of an investigation into the cause of the frequency response decline NERC conducted an Eastern Interconnection Governor Response Survey and found that only 30% of generators provided the expected governor response while 38% provided no response, 13% had no response data, and 19% provided response opposite of what was expected. (Cummings, 2014) The survey did not determine why so many generators do not provide governor response but large thermal generator efficiency can be improved by operating with valves wide open and this practice does thwart governor effectiveness. Alternatively, with no generator response requirement, governor maintenance may not have been a priority. The significant point is that without standards that define required performance and that either compel or pay for response, reliability requirements may not be met.

[5] Figure 3 does not indicate an explicit reliability problem, only a concern. The concern is that if the trend continues then post-contingency frequency will drop low enough to trip the first stage of under frequency load shedding, which is a reliability problem.
[6] As of this writing NERC is investigating the 2013 value and may revise it up.

New technologies compound the problem. A battery energy storage system, for example, may be able to provide full response controlled output over the entire time scale from cycles to hours. Power system reliability is best served if the battery responds as fast as possible but if the stored energy is limited the battery might have an incentive to delay its response so that it can provide maximum power when specific metrics apply (10 minutes, for example). Very fast demand response is similarly challenged by the lack of defined response requirements.

Frequency Responsive Reserves

The lack of response and reserve definitions covering the time immediately after a major contingency has been recognized as a reliability concern with Western Electricity Coordinating Council (WECC), ERCOT, and NERC taking action.

WECC

Similar to the declining eastern interconnection frequency response shown in Figure 3, the frequency response in WECC worsened from 8% in 1985-88 to 12% in 2002 with the trend expected to continue “due to economics and the increasing percentage of generating plants without an adequate frequency response capability (combined cycle, wind generation, etc.)” (WECC 2005) In response WECC formed the Reserve Issues Task Force (RITF) which identified deficiencies in the existing standards both in terms of a lack of technical basis for existing reserves and lack of a fast response requirement. The RITF drafted a methodology for developing a new Frequency Responsive Reserve (FRR) requirement. The methodology established an engineering basis for the amount of FRR required for the interconnection to survive the worst planned for contingency (a category C double contingency generation loss) without under frequency load shed (UFLS) deployment). It also proposed a method to allocate the FRR among BAs based on their load ratio share. Work on the WECC FRR slowed in deference to NERC developing continental requirements. WECC also added a requirement that half of its contingency reserve resources must be equipped with governors in 2012.[7]

NERC

The NERC Frequency Response Initiative started in March 2010. Initial efforts have clarified the reliability concerns of declining frequency response and developed methods for detection of frequency events, measurement of primary frequency response performance, and determination of interconnection frequency response obligation. (Cummings, 2014) This detailed effort identified frequency response withdrawal as a significant concern and determined that it is caused by generators that are not capable of sustaining their initial response or by plant outer-loop control systems that drive

[7] The FERC order approving the standard became effective in January 2014.

generator output back to a setpoint and override governor action. The latter results from "Operating philosophies – operating characteristic choices made by plant operators [and a] desire to maintain highest efficiencies for the plant."

NERC continued the process to address frequency response by developing the FERC approved standard BAL-003-1 – Frequency Response and Frequency Bias Settings. The standard establishes the Interconnection Frequency Response Obligation (IFRO, in MW/0.1 Hz) for each interconnection based upon the largest contingency it is expected to respond to without any under frequency load shed (UFLS) activation. It also allocates the obligation to each BA or Frequency Response Sharing Group (FRSG, a new type of designated entity) based on the BA or RFSG's annual pro-rata generation and load energy total interconnection share. The obligation to set frequency bias settings based on this standard becomes effective in April, 2015 and the obligation to meet the performance requirement itself will be effective in April, 2016. (NERC, 2014a)

While BAL-003-1 established mandatory frequency response requirements for BAs it does not impose specific requirements on generators. As discussed above, the Frequency Response Initiative surveyed generator owners in the eastern interconnection to determine how generator governors were set and how they were performing. The survey found that 30% of generators responded as expected, 38% provided no response, 19% responded opposite of expectations, and 13% had no response data. The survey also found a large range of governor deadband settings. Modeling of the eastern interconnection similarly found that 30% of generators provided frequency response but 2/3 of those exhibited response withdrawal. Only 10% of units provided sustained frequency response.

NERC established the Essential Reliability Services Task Force (ERSTF) in the spring of 2014 to identify any reliability service gaps and to propose both metrics and possible service requirements. The ERSTF is focusing on frequency response, ramps, and voltage support as possible areas to address.

ERCOT

In 2013 ERCOT started to require governor response from all online generators with headroom through the FERC approved region specific standard BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region. Governor response is an interconnection requirement for all generators, not an ancillary service. The requirement is technology specific with generator performance measured against an ideal expectation for that technology. There are significant exceptions with performance not required if a generator is at maximum output or if operating conditions such as auxiliary equipment limitations prevent response. (NERC, 2014a)

ERCOT is also considering additional ancillary services. (J. Matevosyan, 2014) ERCOT currently has a 2800 MW Responsive Reserve Service (similar to spinning reserve) supplied by generators that can fully respond in ten minutes and loads that can respond within 30 cycles, a 400-600 MW Regulation Reserve Service from resources on 4 second automatic generation control (AGC), and a 1100-1500 MW Non-Spinning Reserve Service that must respond within 30 minutes. All are procured through an hourly ancillary services market that is cooptimized with the energy market.

While the existing ancillary services market framework works well ERCOT has found room for improvement. The current ancillary services are based on the inherent characteristics of large fossil fueled generators with Responsive Reserve composed of the combination of fast frequency response, primary frequency response, and contingency response. Declining synchronous inertia during high wind and low load conditions has resulted in higher rate of change of frequency (ROCOF) than in the past. Differences in response characteristics of new technologies (combined cycle gas turbines with duct firing, demand response, storage, wind, etc.) change the historic relationship in the amounts of each service a resource supplies. The five minute energy market and the hourly reliability unit commitment have also reduced the need for the existing ancillary services. (J. Matevosyan, 2014)

ERCOT is addressing these changes with the stated intent to base the ancillary service framework on fundamental system reliability needs rather than on the characteristics of the historic generators. Market based requirements are to be technology neutral and flexible enough to accommodate new technologies. Pay for performance will be implemented where practical. ERCOT will leave regulation unchanged but will split Responsive Reserve into five distinct services:

- Fast Frequency Responsive Reserve 1: 59.8 Hz, automatic response within 30 cycles, 10 minute duration, recovery within 15 minutes
- Fast Frequency Responsive Reserve 2: 59.7 Hz, automatic response within 30 cycles, sustained until recalled by ERCOT, recovery within 3 hours
- Primary Frequency Response
- Contingency Reserves 1: security constrained economic dispatch deployed
- Contingency Reserves 2: manually deployed

The Fast Frequency Response Service (FFRS) and Primary Frequency Response Service (PFRS) are required to arrest the post-contingency frequency drop resulting from the simultaneous failure of two nuclear units (2750 MW) above the 59.3 Hz threshold to avoid UFLS action. ERCOT currently obtains 1400 MW of FFRS from loads that are able to disconnect within 30 cycles. Many actually respond much faster. Creating two types of FFRS should increase the value to ERCOT and the range of resources wishing to supply response.

ERCOT defines Primary Frequency Response (PFR) as the "immediate" proportional increase or decrease in real power output provided by Resources in response to system frequency deviations. As stated above, ERCOT currently requires all online generators to have effective governor response as a condition of interconnection but the generators do not need to restrict their operations in order to assure response. ERCOT intends to require PFR resources to reserve response capacity and have tighter governor dead-bands. While "immediate" is not precise quantification the BAL-001-TRE-1 standard provides technology-specific response requirements. ERCOT has not yet worked through the conflicting requirements for technology-neutral service specifications and the necessity to acknowledge inherent governor response differences among generation technologies.

FFR and PFR are also highly interdependent. While not identical they are somewhat substitutable. ERCOT is developing a methodology to optimize the procurement off FFR and PFR as actual operating conditions change. FFR and PFR in turn impact the contingency reserve requirements.

Non-spinning reserve will also be split into a security constrained economic dispatch deployed service and a manually deployed service.

A potential service to provide inertia-like response is still being investigated. Inertia is still sufficient under all current and expected operating conditions. ROCOF is around 0.2 Hz/second under high wind, low load conditions taking four to six seconds for frequency to decline to the nadir. Simulations show that ROCOF might reach 0.65 Hz for the simultaneous loss of two nuclear units. EPRI is to investigate the value of wind plants providing synthetic inertia.

Frequency Responsive Reserve Summary

The long recognized concern over the decline in the frequency response of each interconnection is being addressed by FERC, NERC, WECC, and ERCOT. The various efforts seem to be converging on some specific principles:

- Frequency response balancing requirements should be the responsibility of the BAs, as are other balancing requirements.
- Requirements should be specified in technology-neutral terms.
- Resource supply should be encouraged from all resources with the technical capability to meet the response requirements (generation, demand response, storage).
- Markets may not be required to obtain response but services should be specified in ways that are compatible with market solutions.

Ramping Requirements

While frequency responsive reserves deal with the very fast time frame that historically have not had specific balancing metrics or performance standards, concerns with ramping involve a slower time frame for which there already are metrics and standards (Figure 2). The BAL-001-1 Real Power Balancing Control Performance standard currently includes Control Performance Standards 1 and 2 (CPS 1&2) which measure each BA's area control error (ACE) and impose annual-average-one-minute and ten-minute balancing requirements under normal conditions. The BAL-002-1 – Disturbance Control Performance standard includes the Disturbance Control Standard (DCS) and requires rebalancing the BA within 15 minutes of a contingency. Version two of BAL-001, which was approved by the NERC Board of Trustees but has not yet received FERC approval, replaces CPS 2 with a Balancing Authority ACE Limit (BAAL) metric and 30 minute balancing requirement. (NERC, 2014a) DCS may be retired after experience is gained with BAAL. These standards have metrics that will detect imbalances in the sub-hourly to multi-hour ramping time frame and BA balancing requirements that will maintain power system reliability if met. The concern with ramping is not that there is a gap in the balancing requirements during the ramping time frame. Instead there are concerns that changes in the generation mix are making meeting the reliability standards requirements during ramps more difficult and an additional service may be required to help BAs meet those balancing standards requirements.

The ramping concern is an economic as well as a reliability issue. It occurs when the generation that has been selected to meet hourly energy requirements at lowest cost does not have sufficient flexibility to follow the changes in net load. Figure 4 shows a very simplistic example of a power system with enough low cost generation to meet its energy requirements but when the load increases by 300 MW in 30 minutes at 8:00 the base load generation is unable to keep up. (Kirby and Milligan, 2009) Faster but more expensive generation must be committed and dispatched until the low cost generation can catch up. Real situations must deal with generator minimum load constraints and startup times so the situation is more complex and more expensive than shown but the important point is the same: it is not a lack of on-line generating capacity that is the problem, the problem is a lack of ramping capacity. Historically this situation has been relatively rare. Figure 5 presents histograms of load ramping requirements and on-line thermal generation ramping capabilities for three very different BAs for 2002. (Kirby and Milligan 2005) Data from hydro units was not available so the figure actually understates the available on-line generation ramping capability. As can be seen, the solid lines showing the on-line generation ramping capability greatly exceed the dashed lines showing the net-load ramping requirements for each BA studied. Not unexpectedly the WAPA on-line thermal down ramping capability greatly exceeds the up ramping capability because large coal fired generators are typically economically dispatched closer to full load than to minimum. With such an abundance of ramping capability naturally on-line when conventional generators dominated and were economically committed and dispatched there was little concern with the need for an explicit inter-hour ramping service.

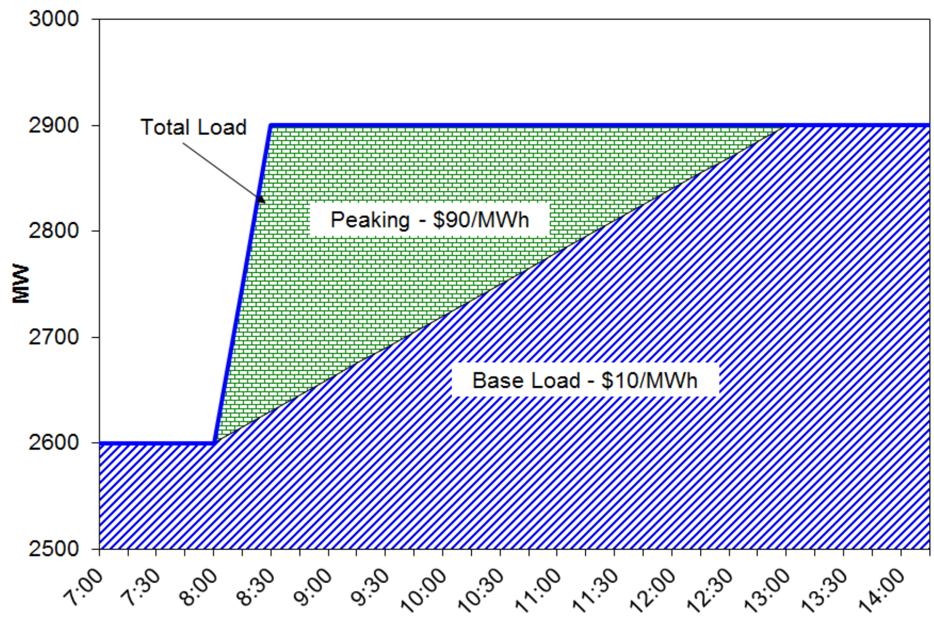

Figure 4 Ramping requirements change the energy generation selection.

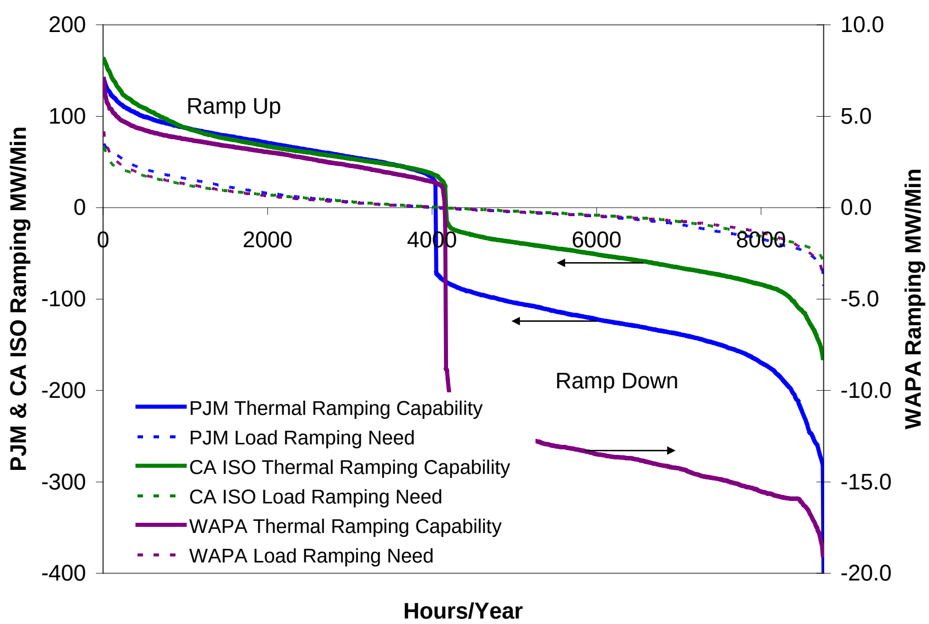

Figure 5 BA ramping capability historically typically exceeded need.

Two Types Ramping Concern

Increasing amounts of wind and solar generation raise the concern that ramping capability may become a difficult problem for power system operators. Figure 6 shows how CAISO expects solar generation to impact the net load shape by 2020 (CAISO's famous "duck curve"), greatly increasing the evening ramp up requirements.[8] (NERC and CAISO, 2013) Figure 7 shows a 2007 ERCOT event where wind generation dropped by 1500 MW over two hours. An important difference between the two types of ramping events is that the solar ramps will happen every sunny day at known times while the large wind ramp events happen infrequently (tails events) and at random times.[9] The large wind ramps are similar to conventional generation contingencies except they are much slower and may not qualify for contingency reserve deployment.[10] The large wind ramps may be able to be addressed with a contingency-like non-spinning or quick-start reserve. The large daily solar ramps will need to be incorporated into the normal reliability constrained unit commitment and economic dispatch.

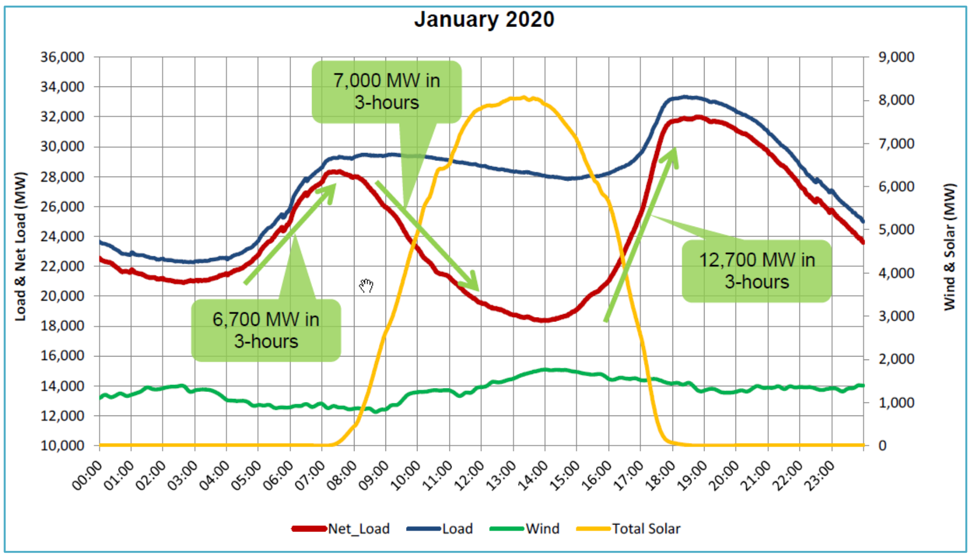

Figure 6 CAISO expected solar and wind generation in 2020.

Wind and solar also displace controllable conventional generation, reducing the ramping resources at the same time that ramping requirements are increased. Detecting the imbalance is not a problem, additional balancing metrics are not needed. Knowing how well each BA must balance generation and load to assure reliability is also not a problem, existing standards are not needed. CPS 1 and 2, DCS, and BAAL are not challenged by the ramping concern. There are no reliability standards or metrics gaps as there are with fast frequency response. Instead there is a concern with the

---

[8] Solar thermal generation can include thermal storage and mitigate large ramps.
[9] Wind ramp forecasting may provide hours of warning to large ramp events.
[10] Solar generation also experiences ramps at times other than sunrise and sunset due to clouds.

availability and cost of ramping resources that will be necessary to help BAs meet their reliability requirements at the lowest cost.

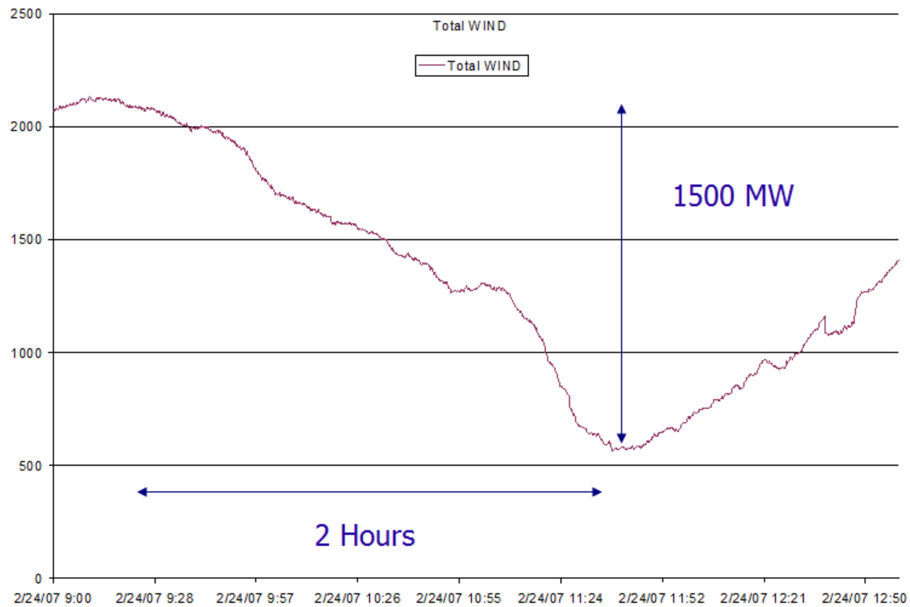

Figure 7 In 2007 ERCOT experienced a 1500 MW drop in wind generation over two hours.

CAISO Flexible Ramping Product

CAISO is sufficiently concerned with the potential for increasing ramping requirements and decreasing ramping resources that it is developing a flexible ramping product. (L. Xu and D. Tretheway, 2014) CAISO has found that the real-time unit commitment process (also known as the real-time pre-dispatch process) does not always select resources with sufficient ramping capacity to handle the 5-minute to 5-minute system load and supply changes. This forces system operators to rely on increased regulation services (expensive) and can result in energy prices set by the administrative penalty processes. The proposed flexible ramping product will create a ramping margin on top of the forecasted ramping need which the unit commitment and economic dispatch already account for. Similar to other ancillary service reserves, flexible ramping reserve suppliers will be compensated based on the marginal opportunity cost.

CAISO's current proposal is to procure ramping capacity in the day-ahead and real-time markets. The amount of ramping procured will depend on the forecasted net-load change plus a reserve for forecast error uncertainty based on the historical forecast error pattern for each five-minute interval of the day with a 90-95% confidence. A demand curve will be used to adjust the amount of ramping forecast error covered. The real-time requirement will be updated every five minutes. Ramping will be a system wide service at first but locational requirements may be added later. The ramping clearing prices paid to all resources will be limited to the lost opportunity cost from energy. Generators that do not have a monthly resource adequacy flexible capacity requirement can set their ramping capability to zero and avoid being ramped (and forgo ramping payments). Ramping capability is determined by a resource's capability to ramp over three hours though faster ramp rates (with shorter durations) are valued in the real-time market. Fast start units are considered. Interestingly, self-provision of flexible ramping will not be allowed because of the interactions with the energy market and the potential for market manipulation. Actual ramping costs are to be allocated based on five-minute load movements, the combination of uninstructed and self-scheduled generation movements, and import/export ramps. All resources in a given category (load, supply, or import/export) will be netted prior to determining the initial division of system wide costs.

MISO

MISO is also considering adding a ramping product to its day-ahead and real-time markets "to provide a determined quantity of ramp capability from dispatchable generation resources to respond to the expected variability and unexpected variations of net load." (N. Nivad and G. Rosenwald, 2013) The general outlines are very similar to those of the CAISO. Requirements will initially be system-wide but zonal requirements will be implemented if required. Fast start units will be considered and ramping procurement will be cooptimized with energy and the other ancillary services. A ramp capability demand curve will be utilized. The ramping clearing prices paid to all resources will be limited to the lost opportunity cost from energy and ancillary service markets. The costs of ramp capability are proposed to be allocated to those that primarily benefit from the product (the load and exports would be allocated the cost) the same way contingency reserve costs are allocated. About 90% of the ramping need is due to load and interchange changes. MISO expects annual cost savings of $3.8 - $5.4M after consideration of the impact of an additional $2.0 - 4.0M in operational costs to provide the ramp capability products. Alternatives such as increasing the amount of regulation or spinning reserve are more expensive.

Implications for Generators

There are several implications for generators wishing to prosper in an environment with increased wind and solar generation. Clearly there will be a need for generation that can start and ramp quickly and economically. Large ramping range, and therefore low minimum loads, are important for both generators that can cycle daily (or twice a day) and generators that would prefer to remain on line.

Shifting the net-load off-peak time from overnight to midday will likely not have a major impact on generation equipment but it may have important staffing implications.[11] Demand response programs that traditionally focused on shifting load from midday to night time may need to refocus and move load back to the times of high solar production.

Summary and Conclusions

Two new areas of interest in ancillary services are seeing increased attention among policy makers, market designers, and reliability organizations: frequency response and ramping. Generator owners will want to be aware of potential new opportunities to profit by providing services to the power system. They will also want to be aware of changing obligations under NERC standards.

Frequency response has been a technical concern in all four North American interconnections for decades and it is now beginning to be addressed. Historically, while the need for inertia and governor response were technically well understood, there were no explicit standards that required specific performance in the cycles-to-minutes time frame. Instead, reliability was maintained because of the inherent characteristics of the incumbent generators. As the generation mix changes new metrics, standards, and response services are being considered to explicitly address frequency response.

Ramping requirements are also of concern with increased wind and solar generation increasing net-load ramps while displacement of controllable thermal generation is reducing the amount of on-line flexibility. New metrics and standards are not required but additional ramping resources may be needed. Lower minimum loads and reduced cycling costs are also beneficial attributes for conventional generators wishing to prosper as wind and solar generation increase.

Generator owners should always consider their options in supplying energy and the existing ancillary services (regulation, spinning reserve, and non-spin) to find the most profitable mix each hour. As markets for frequency response and ramping develop, generator owners should evaluate these options as well. Reducing cycling costs and lowering minimum loads increase the range of available options and the potential profits. Especially when considering investments, recall that while energy and ancillary services are absolute reliability requirements the system operator almost always has economic alternatives for their supply. Alternatives include other generators, demand response, and storage. Reliability and economics are inseparable. Generators should maximize their flexibility over all timeframes in order to maximize their profitability.

[11] There may be a benefit for conventional generators that are sensitive to ambient temperature with their peak capacity required later in the day when it may be cooler.

References

R. Cummings, 2014, *EI Frequency Response: Overview of Efforts to Improve Frequency Response in the Eastern Interconnection*, NERC, MRO Reliability Workshop, May 28

B. Kirby, M. Milligan, 2009, *Capacity Requirements to Support Inter-Balancing Area Wind Delivery*, NREL/TP-550-46274, July

B. Kirby, M. Milligan, 2005, *A Method and Case Study for Estimating The Ramping Capability of a Control Area or Balancing Authority and Implications for Moderate or High Wind Penetration*, American Wind Energy Association, WindPower 2005, May.

J. Matevosyan, 2014, *Future Ancillary Services Developments in ERCOT*, NERC ERSTF presentation, August 7

MISO, 2014, https://www.misoenergy.org/WhatWeDo/MarketEnhancements/Pages/RampManagement.aspx Accessed August 22

N. Nivad and G. Rosenwald, 2013, *Ramp Capability Product Design for MISO Markets*, MISO, December, https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf

NERC and CAISO, 2013, *2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach*, North American Reliability Corporation and California Independent System Operator, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf, November

NERC, 2014a, *Reliability Standards for the Bulk Electric Systems of North America*: *Updated August 5, 2014*, www.nerc.com

NERC, 2014b, *State of Reliability 2014*, http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf

WECC Reserve Issues Task Force, 2005, *Frequency Response Standard White Paper*, WECC, November 2005

L. Xu and D. Tretheway, 2014, *Flexible Ramping Products Incorporating FMM and EIM: Revised Straw Proposal*, CAISO, August, http://www.caiso.com/Documents/RevisedStrawProposal_FlexibleRampingProduct_includingFMM-EIM.pdf