21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

CIGRE US National Committee
2015 Grid of the Future Symposium

# Analysis of the Effects of a Flexible Ramping Ancillary Service Product on Power System Operations

**I. KRAD[a], E. IBANEZ[a], E. ELA[b]**
**[a]National Renewable Energy Laboratory (NREL)**
**[b]Electric Power Research Institute (EPRI)**
**USA**

## SUMMARY

The recent increased interest in utilizing variable generation (VG) resources in power systems, such as wind and solar generation, has motivated interested in investigating new operational procedures. While these resources provide desirable value to the system (e.g., no fuel costs or emissions), interconnecting them into the main power system provides unique challenges. The variable, non-controllable nature of their power in particular requires significant attention. This directly results in increasing the variability and uncertainty of the power system. One way to handle this is via the use of new operating reserve schemes. Operating reserves provide upward and downward generation and ramping capacity to counteract uncertainty and variability prior to their realization. For instance, uncertainty and variability in the real-time dispatch can be accounted for in the hour-ahead unit commitment. New operating reserve methodologies that specifically account for the increased variability and uncertainty due to VG are currently being investigated and developed by academia and industry. This paper examines one method inspired by the new operating reserve product being proposed by the California Independent System Operator (CAISO). The method is based on the examination of the potential ramping requirements at any given time and enforcing those requirements via a reserve demand curve (RDC) in the market clearing optimization as an additional ancillary service product.

## KEYWORDS

Flexibility reserves, ancillary services, unit commitment, economic dispatch, power system operations, automatic generation control, mixed-integer programming, reserve demand curve

ibrahim.krad@nrel.gov

## INTRODUCTION

Power system operators have historically maintained the balance of active power in real time by scheduling and deploying operating reserves. These operating reserves are designed for different temporal resolutions and for different purposes. Contingency reserves are designed to protect the system against unforeseen system events, typically the loss of generation or transmission assets. Regulation reserves are provided via automatic generation control and are used as secondary frequency response to maintain the real-time balance of active power every few seconds. A new class of operating reserves known as flexibility reserves is being developed to account for the expected ramping requirements in the system beyond the timeframe of regulation reserves. The use of these flexibility reserves is expected to be widespread as variable generation (VG) sources penetrate the system and, consequently, the variability and uncertainty in the power system increases.

There are several variations of this class of flexibility reserves currently being researched and proposed in literature. The authors of *Dynamic operating reserve strategies for wind power integration*, develop a dynamic operating reserve requirement that is a function of the wind forecast errors and wind variability. The authors of *Credibility theory applied for estimating operating reserve considering wind power uncertainty* present a dynamic operating reserve methodology based on the risk involved in wind forecast errors. Two risk indices are introduced known as the wind power at risk and the conditional wind power at risk. These indices are unified with credibility theory and a final dynamic reserve requirement is calculated. The authors of *Computation of Dynamic Operating Balancing Reserve for Wind Power Integration for the Time-Horizon 1–48 Hours* present a reserve methodology focusing on the planning temporal horizons (from day-ahead operation up to hour-ahead operation) to account for net load uncertainties occurring at these resolutions. The authors of *Operating reserves assessment in isolated power systems with high wind power penetration* present an operating reserve calculation methodology based on the variability in wind speed and electrical demand. By utilizing a convolution approach, a probability distribution of the reserve requirements at real-time temporal resolutions can be obtained and operating reserve requirements can be defined. A comprehensive comparison of different operating reserve strategies used in recent wind integration studies is available in *Methodologies to Determine Operating Reserves Due to Increased Wind Power* and *Operating Reserves and Variable Generation: A comprehensive review of current strategies, studies, and fundamental research on the impact that increased penetration of variable renewable generation has on power system operating reserves*.

There are also several similar flexibility reserve products being proposed by industry experts. In *Market solutions for managing ramp flexibility with high penetration of renewable resource*, a mathematical formulation to be used with the Midcontinent Independent System Operator's (MISO) market-clearing software is proposed. This formulation includes the flexibility reserve product and is designed to allow the operator to acquire enough ramping capacity to meet expected ramping events in the net load profile. One potential side effect of this product is the reduction in scarcity pricing events that result from insufficient ramping capacity in the system. The California Independent System Operator (CAISO) is also developing a similar product as proposed in [8]. This reserve product serves as the motivation for this paper. A more detailed description of this reserve methodology is presented in the next section.

## FLEXIBILITY RESERVE METHODOLOGY

The flexibility reserve requirement examined in this paper is motivated by the methodology proposed in *Flexible Ramping Products: Incorporating FMM and EIM*. The reserve requirements are calculated for both the upward and downward direction and implemented in the optimization as a flexibility reserve demand curve (FRDC). The goal of this reserve methodology is to quantify the amount of ramping requirement needed in both the upward and downward directions to ensure reliability while procuring that ramping capacity in the most economical way possible. A typical FRDC is shown in figure 1.

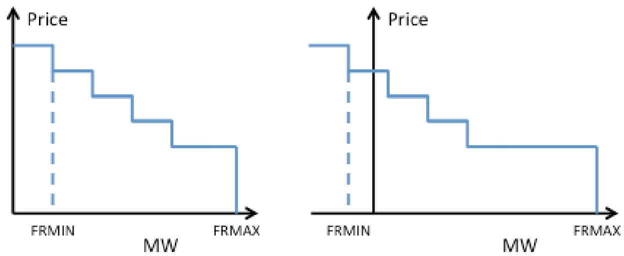

Figure 1 – Typical FRDC with positive FRMIN (left) and negative FRMIN (right)

The minimum ramping requirement needed in the system is defined as FRMIN and is based on expected ramps occurring in the net load profile (i.e., load minus VG). Similarly, the maximum allowable ramping requirement is defined as FRMAX. If the FRMIN calculation yields a negative requirement, the FRDC is shifted to the first nonnegative block and extended to FRMAX if necessary. Each block on the FRDC has an associated penalty cost. This allows the optimization to procure ramping capacity only when the marginal cost of procuring that capacity is less than the penalty cost associated with that same capacity. As can be seen from Figure 1, the penalty costs associated with the ramping requirements decrease as the requirement increases. The breakpoints on the FRDC are shown in Table I. Due to available data limitations, one year of data was used to determine these FRDC characteristics rather than multiple years of historical data as suggested in *Flexible Ramping Products: Incorporating FMM and EIM*.

TABLE I
FLEXIBLE RESERVE DEMAND CURVE CHARACTERISTICS

| | Penalty Cost in Upward Direction [$/MW] | Penalty Cost in Downward Direction [$/MW] |
|---|---|---|
| Block 1 | 250 | 250 |
| Block 2 | 24 | 3.6 |
| Block 3 | 15 | 2.25 |
| Block 4 | 8 | 1.2 |
| Block 5 | 2.5 | 0.375 |

The step size associated with the FRDC depends on the temporal resolution being solved by the optimization. During the day-ahead optimizations, a step size of 250 MW is used. During the real time optimizations, a step size of 50 MW is used. The variable FRMIN is also a function of the temporal resolution and its calculation detailed below.

- Day-Ahead: FRMIN is calculated based on expected ramp in the net load profile at each hour in the simulation. FRMAX is taken as the 2.5$^{th}$ and the 97.5$^{th}$ percentiles of these ramps for each hour of the day within a month.
- Hour-Ahead: FRMIN is calculated based on net load ramps occurring at each 5-minute interval occurring within each 15-minute hour-ahead solution. FRMAX is taken as the 95% confidence interval of FRMIN for each hour of the day within a month.
- Real-Time: FRMIN is calculated based on the expected ramp in the net load profile at each 5-minute interval occurring in both the binding and nonbinding intervals of the optimization. FRMAX is taken as the 95% confidence interval of FRMIN.

Each one of these products had an upward and downward FRDC. The hour-ahead and real-time products are implemented as five-minute products while the day-ahead is a 60-minute product.

## ANALYSIS TESTBED

The analysis performed in this study leverages the Flexible Energy Scheduling Tool for Integrating Variable generation (FESTIV) developed by the National Renewable Energy Laboratory (NREL).

This tool is a steady-state power system simulation tool that captures all temporal resolutions in the generation scheduling process starting from the day-ahead unit commitment all the way through AGC. FESTIV contains a security constrained day-ahead unit commitment sub-model (DASCUC), a security constrained real-time unit commitment sub-model (RTSCUC), a security constrained real-time economic dispatch sub-model (RTSCED), and an AGC sub-model. All of these models are interconnected such that the solution of each sub-model directly serves as the input into the next sub-model. This interconnected simulation workflow allows FESTIV to accurately capture power system operations as performed today. FESTIV is able to provide economic metrics in terms of total system production costs and locational marginal prices (LMPs). It is also able to provide reliability metrics in terms of area control error, or ACE, taken as the difference between the sum of generation and electrical demand.

A modified version of the IEEE 118-bus test system is used for this analysis. This system was updated to better capture current generation portfolios based on available production cost data [9]. Wind and solar generation assets were added to the system to reflect future penetration scenarios. Wind and solar resource data is based on available data from northern California [10] and selected to represent an average energy penetration of approximately 33%, evenly split between wind and solar generation. These resources were sited to maximize access to transmission and minimize potential curtailment. This system was simulated for four weeks (the third week in January, April, July, and October) to capture the seasonal trends apparent in load and VG data.

Six cases were simulated in order to thoroughly investigate the impacts of this flexibility reserve methodology: Case 1 is the base case without the flexibility reserve product; Case 2 includes the flexibility reserve product in all operational timeframes; Case 3 removes the flexibility reserve product from the day-ahead timeframe; Case 4 removes the flexibility reserve product from the day-ahead and real-time dispatch timeframes; Case 5 is the base case but does not consider the transmission constraints nor the flexibility reserve product; and Case 6 includes the flexibility reserve product at all temporal resolutions but does not consider any transmission constraints (i.e. no assumptions are made about energy deliverability and intra-area congestion).

## RESULTS

A summary of the numerical results is shown in figure 2. The Absolute ACE in Energy (AACEE, top left plot in figure 2) is defined as the integral of the absolute value of the ACE observed in the system for the entire study period and is measured in MWh. This metric provides insight into how well the system was balanced. In general, the inclusion of the FRDC resulted in an increase of the AACEE across all cases. This could be because the FRDC helps prepare the system for the additional uncertainty in the system, but may not provide much benefit with respect to the variability in high penetration scenarios. The top right plot in figure 2 shows the total system production cost. This is the cost to supply load taken as the product of the marginal cost of providing energy for each generator and the amount of energy it produced, including both no-load and start-up costs. Notice that these costs remain relatively unchanged across cases. The lower left plot in figure 2 shows the number of scarcity pricing events occurring for each case across all weeks. Notice that including the FRDC noticeably reduces the number of intervals that exhibit scarcity prices across all cases and weeks. The bottom right plot in figure 2 shows the amount of curtailed load across all cases. The inclusion of FRDC reduces the amount of real time infeasibilities across all cases, further implying the benefit with respect to uncertainty over variability. Another interesting observation from this plot is that the reduction of real time infeasibilities is not as significant when the FRDC is removed from the day-ahead timeframe (Case 3). The reduction is slimmer when the FRDC is removed from the real-time economic dispatch as well (Case 4). This could be because forecast errors at the day-ahead timeframe are significant as are the potential net load ramping events. Not allowing the day-ahead to account for these ramping needs could significantly expose the reliability of the system.

Figure 3 shows the amount of available ramping capacity in October for Case 3. Notice that most instances of load shedding occur due to insufficient ramping capacity. The inclusion of the FRDC, in general, results in the commitment of additional excess thermal generation. This is expected since the additional ramping requirements must be met by the online thermal fleet. This excess generation is apparent across all weeks. If the FRDC is removed from the day-ahead simulations, the amount of excess thermal generation trends closer to the case without the FRDC entirely. The FRDC results with the commitment of slower thermal generators to meet the flexibility requirement and by removing it from the day-ahead optimization, the system has less options to choose from to fulfil the flexibility requirement. This leads to the inability to meet the full real-time requirement, as is evident from the increase in unfulfilled requirement. The amount of the requirement that was not fulfilled increased by ~31% in January, ~11% in July, and ~33% in October by removing the requirement from the day-ahead optimization. In April, the amount unfulfilled is actually reduced by ~8%. This could be due to low loading conditions that are not as sensitive to the generation mix.

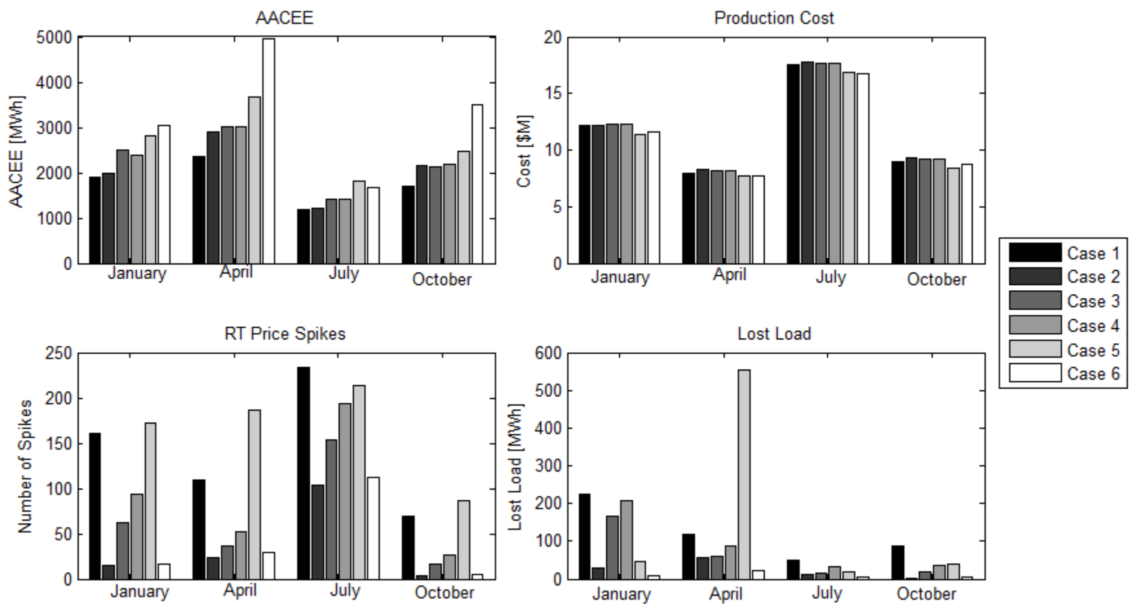


Figure 2 – Numerical results of simulations across all cases and all weeks

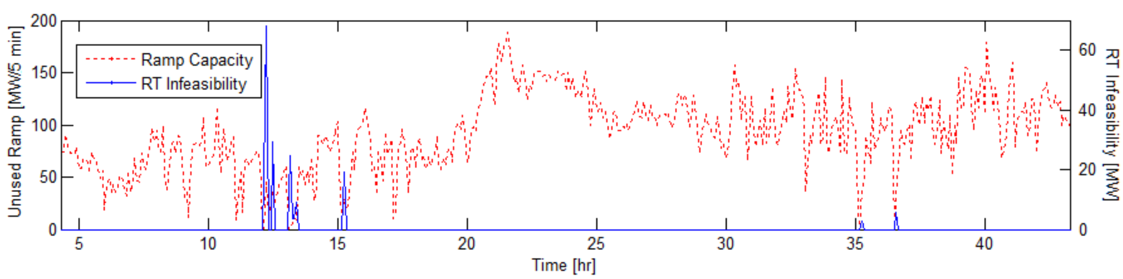


Figure 3 – Available ramping capacity and real time infeasibilities in Oct without Flexiramp in the DA

The omission of network constraints results in a decline in reliability metrics. This occurred because without the network constraints, the economic dispatch solution is purely merit based, and often resulted with fewer generator commitments. This unconstrained dispatch offers less flexibility to mitigate the variability realized in real-time operations. Specifically, lack of sufficient regulation down capacity resulted with the accumulation of positive ACE, particularly during times of maximum VG output. In April, i.e. with low loading, the limited online generation mix cannot accommodate real-time net load ramps, resulting with substantial load shedding. Online generators are operating at maximum capacity and the system must resort to curtailing load. By comparing Cases 2 and 3, we observe that including network constraints minimally impacts the benefits of these flexibility ramping reserves.

## CONCLUSION

As the power system evolves, operators must adapt traditional operating strategies to improve the cost effectiveness and reliability. As more wind and solar generation is added to the system, operators will need to find ways to mitigate their operational challenges, namely the increased variability and uncertainty. One potential solution is the use of flexibility (or ramping) reserves. This paper analysed one potential implementation of these flexibility reserves based on a proposal from CAISO. While the impacts on production cost are relatively small, there could be significant implications on reliability. The analysis in this paper shows that this reserve product could offer more value in managing the uncertainty of VG than the variability of VG. It is also important to include this reserve product in the day-ahead optimization since the commitment of slower thermal generators can significantly help reduce the imbalance seen during operation. Removing it from the day-ahead optimization could result in adverse effects on the system imbalance, i.e. more accumulated ACE. The flexibility reserve product was able to reduce the number of scarcity pricing events (i.e. real time prices that exceed 1000 $/MWh), that occurred mostly due to insufficient ramping capacity. As long as these reserves are co-optimized with energy, these simulations show that deliverability of these reserves was not a concern with respect to their actual deployment.

## BIBLIOGRAPHY


[1] K. De Vos and J. Driesen, "Dynamic operating reserve strategies for wind power integration," *Renewable Power Generation, IET* , vol.8, no.6, pp.598-610, August 2014.

[2] Z. Xue, G. Li, and M. Zhou, "Credibility theory applied for estimating operating reserve considering wind power uncertainty," *PowerTech, 2011 IEEE Trondheim*, pp.1-8, 19-23 June 2011.

[3] N. Menemenlis, M. Huneault, and A. Robitaille, "Computation of Dynamic Operating Balancing Reserve for Wind Power Integration for the Time-Horizon 1–48 Hours," *IEEE Transactions on Sustainable Energy*, vol.3, no.4, pp.692-702, Oct. 2012.

[4] L.S. Vargas, F.A. Larrain, and H. Verdejo, "Operating reserves assessment in isolated power systems with high wind power penetration," *International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*, pp.1-6, 7-10 July 2014.

[5] H. Holttinen, M. Milligan, E. Ela, N. Menemenlis, J. Dobschinski, B. Rawn, R.J. Bessa, D. Flynn, E. Gomez-Lazaro, and N.K. Detlefsen, "Methodologies to Determine Operating Reserves Due to Increased Wind Power," *IEEE Transactions on Sustainable Energy*, vol.3, no.4, pp.713-723, Oct. 2012.

[6] E. Ela, M. Milligan, and B. Kirby, "Operating Reserves and Variable Generation: A comprehensive review of current strategies, studies, and fundamental research on the impact that increased penetration of variable renewable generation has on power system operating reserves." 103 pp.; NREL Report No. TP-5500-51978. 2011.

[7] N. Navid and G. Rosenwald, "Market solutions for managing ramp flexibility with high penetration of renewable resource," *IEEE Trans. Sustainable Energy*, vol. 3, no. 4, pp. 784, 790, Oct. 2012.

[8] L. Xu and D. Tretheway, "Flexible Ramping Products: Incorporating FMM and EIM." California Independent System Operator. Draft final proposal. December 2014. <https://www.caiso.com/Documents/DraftFinalProposal_FlexibleRampingProduct_includingFMM-EIM.pdf>.

[9] G. Stark, "Integration Costs." NREL Technical Report. NREL Report No. TP-5D00-64502. 2015.

[10] D. Lew, G. Brinkman, E. Ibanez, A. Florita, M. Heaney, B. M. Hodge, M. Hummon, G. Stark, J. King, S. A. Lefton, N. Kumar, D. Agan, G. Jordan, and S. Venkataraman, "Western Wind and Solar Integration Study Phase 2," National Renewable Energy Laboratory, Golden, CO. NREL Report No. TP-5500-55588.