Operational Impacts of Operating Reserve Demand Curves on Production Cost and Reliability

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Abstract—**The electric power industry landscape is continually evolving. As emerging technologies such as wind, solar, electric vehicles, and energy storage systems become more cost-effective and present in the system, traditional power system operating strategies will need to be reevaluated. The presence of wind and solar generation (commonly referred to as variable generation or VG) may result in an increase of the variability and uncertainty in the net load profile. One mechanism to mitigate this issue is to schedule and dispatch additional operating reserves. These operating reserves aim to ensure that there is enough capacity online in the system to account for the increased variability and uncertainty occurring at finer temporal resolutions. A new operating reserve strategy, referred to as flexibility reserve, has been introduced in some regions. A similar implementation is explored in this paper, and its implications on power system operations are analyzed.**

Index Terms—**Operating reserves, security-constrained unit commitment, security-constrained economic dispatch, flexibility reserves, flexi-ramp, ancillary services, reserve demand curve**

I. Introduction

As emerging technologies continue to become more significant players in the power system, operating strategies will need to evolve that allow system operators to mitigate adverse effects while maximizing system benefits. Wind and solar generators, electric vehicles, energy storage systems, and distributed generation located throughout the distribution system have recently drawn significant attention. These technologies may increase the variability and uncertainty in the power system. Power system operators may need new and improved methods to maintain the real-time balance between electricity generation and consumption. Traditionally, system operators have utilized a combination of operating reserves [1]. These requirements are typically based on simple heuristics developed independently by each footprint, without any consensus on a universal methodology to calculate how much reserves the system operator must acquire. Although contingency reserves are typically designed with N-1 reliability in mind, there is still much discussion about how operating reserves are procured.

New operating reserve methodologies are explored to address the additional variability and uncertainty from variable generation (VG) resources. The authors of [2] presented a dynamic operating reserve requirement that is updated on an hourly basis to account for the variability of wind power. This dynamic requirement is driven by probabilistic forecast errors as well as the short-term variability of wind power generation. Their analysis showed that there are significant opportunities to modify a static reserve requirement, and this modification could potentially reduce the cost per MWh of wind power injected. The authors of [3] proposed a dynamic reserve requirement methodology based on the probability of load shedding. The requirement is determined by considering the reliability requirements of the system throughout the entire year with respect to the number of allowable load-shedding incidents per year. Their analysis showed that increasing wind power generation in the system increases the need for operating reserves and that reserve requirements that consider longer temporal horizons typically result in requirements larger than those for shorter temporal horizons. The authors of [4] formulated a dynamic economic dispatch problem to simultaneously schedule energy and reserves utilizing an interior point algorithm. The model converged well while improving computational speed. The authors of [5] proposed an hourly, dynamic reserve requirement methodology based on risk indices, such as the loss of load probability. This formulation allows the system operators to examine the trade-off between acceptable risk levels and operating cost and decide on a reserve requirement that best suits the current operating needs of the system.

The industry is also interested in dynamic reserves. The authors of [6] developed a flexibility reserve methodology to address ramping concerns that can be integrated within the Midcontinent Independent System Operator's day-ahead market model. This method aims to prepare generation assets for variability and uncertainty in the net load. One of the potential benefits of this ramping product is the potential reduction in real-time scarcity events. The California Independent System Operator recently developed a proposal to incorporate a flexible ramping ancillary service [7]. This product is meant as a dynamic reserve requirement implemented via a multi-segment reserve demand curve to address potential net load ramping concerns. This was motivated by the fact that the commitment and dispatch of generators does not always account for the variability and uncertainty in the net load that occurs at finer temporal resolutions. This product was developed with the intention of curbing the system's reliance on regulating ancillary services and interchange flows during times of insufficient or over-generation. Another motivation is to reduce the volatility in the locational marginal prices (LMPs) by reducing the number of scarcity pricing events caused by insufficient ramping capacity. The basic idea is that including the flexible ramping service will provide a ramping margin on top of forecasted net load ramps in multi-interval unit commitment and economic dispatch.

The goal of this paper is to analyze the economic and reliability implications of a dynamic operating reserve product on power system operations. The intent of this reserve product is to prepare the system for real-time flexibility needs by dynamically modifying the operating reserve requirement. Economic implications will be measured via total system production costs and LMP. Reliability implications will be measured based on the area control error (ACE), i.e., the imbalance between generation and consumption.

The rest of this paper is organized as follows: Section II details the flexible ramping product methodology, Section III describes the case study used in this analysis, Section IV provides the results, and Section V concludes the paper with final remarks.

II. Methodology and Determination of Requirements

The analysis performed in this study utilized the Flexible Energy Scheduling Tool for Integrating Variable generation (FESTIV) developed by the National Renewable Energy Laboratory (NREL). This is a steady-state power system operations simulation tool. FESTIV captures the entire scheduling process, from the day-ahead unit commitment through the generator automatic generation control (AGC). FESTIV simulates an integrated set of scheduling tools: security-constrained day-ahead unit commitment (DASCUC), security-constrained real-time commitment (RTSCUC), security-constrained real-time economic dispatch (RTSCED), and AGC. Each model is interconnected to subsequent models such that the outputs of one model serve as the inputs into the next. FESTIV is built in MATLAB and GAMS [8]-[9]. More details about the model can be found in [10].

The flexibility reserve requirements were implemented following the description provided in [7]. Although the calculation and magnitude of the requirements change among the different models in FESTIV (DASCUC, RTSCUC, RTSCED), the demand curve has a similar behavior.

Fig. 1 (left) shows a diagram with the basic shape of the flexible reserve demand curve (FRDC). A demand curve is determined dynamically for each step in the simulation. The minimum flexibility reserve requirement (FRMIN) represents the expected ramp need of the system. A penalty cost is associated with the FRMIN. The demand curve is in place such that ramping capability above the FRMIN can be purchased when cost effective. There are a number of additional steps for increasing need with decreasing penalty costs. The last step is extended to the maximum flexible reserve value (FRMAX).

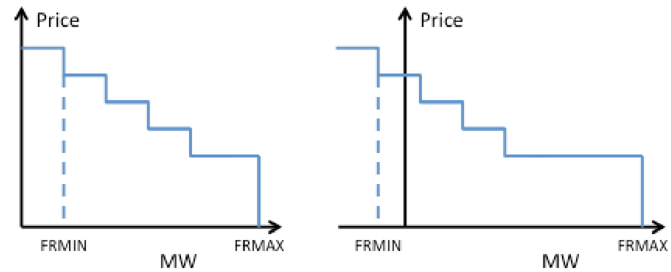

Fig. 1. Example FRDC

The optimization algorithm will select the reserve level on the demand curve where the marginal cost of providing the service is less than the penalty cost. The use of demand curves allows the definition of decreasing penalty costs, which provide more granularities to the optimization. Both upward and downward requirements are held in these simulations. In the event that FRMIN is negative for a given requirement (Fig. 1, right) the supply curve is shifted.

Table I summarizes the different parameters that, along with FRMIN and FRMAX, determine the supply curves for each solution step. The goal was to match the methodology as closely as possible to that of [7] while making necessary changes due to differing systems and data availability.

Table I
FRDC Characteristics

	DASCUC	RTSCUC	RTSCED
Step Width [MW]	250	50	50
Penalty Costs, Up Direction [$/MW]	250, 24, 15, 8, 2.5		
Penalty Costs, Down Direction [$/MW]	250, 3.6, 2.25, 1.2, 0.375		

The description in [7] suggested a number of system factors that contribute to the determination of flexibility reserve requirements. In this paper, we consider the contribution of load and VG toward that requirement. We do not consider the impact of self-scheduling generators or interchange with other regions because neither is considered in our modeling. In the absence of many years of data to determine the requirements, as suggested in [7], data for one year was utilized.

FRMIN is calculated differently for each simulation step:

- <u>DASCUC</u>: Day-ahead flexibility requirements are calculated based on the hourly difference in net load (i.e., load minus VG generation). FRMIN is calculated based on the difference in day-ahead forecasts for each hour. FRMAX is calculated as the 97.5th and 2.5th percentiles for net load hourly ramps for each month and hour of the day for the upward and downward directions, respectively. It is a 60-minute product.

- <u>RTSCUC</u>: Intra-day unit commitment happens with a frequency of 15 minutes in the simulations. FRMIN is calculated as the difference between the forecast for each of the 5-minute RTSCED steps that correspond to each RTSCUC solution. FRMAX is calculated as the 95%

confidence interval for FRMIN for each hour of the day within a month. Requirements are calculated for the binding and advisory intervals. It is a 5-min product.

- RTSCED: Real-time economic dispatch flexibility reserve requirements are based on the difference of each consecutive 5-minute forecasts for net load, both for the binding and advisory intervals. FRMIN values are calculated as the expected 5-minute ramps in the net load forecasts. Up and down FRMAX values are calculated to cover 95% of those differences. It is a 5-min product.

Fig. 2 shows plots of the maximum requirement for a single day for the week simulated in October in both the upward (upward ramps) and downward (downward ramps) directions. Although the actual requirements will change with every interval, each month exhibits similar trends, and the magnitude of the requirements at each temporal resolution is also comparable among months.

TABLE II
UPDATED IEEE 118-BUS TEST SYSTEM CHARACTERISTICS

System Characteristics	
Coal Capacity [GW]	2.30
Combined-Cycle Capacity [GW]	2.76
Combustion Turbine Capacity [GW]	2.52
Annual Solar Energy Penetration [%]	17.45
Annual Wind Energy Penetration [%]	16.98

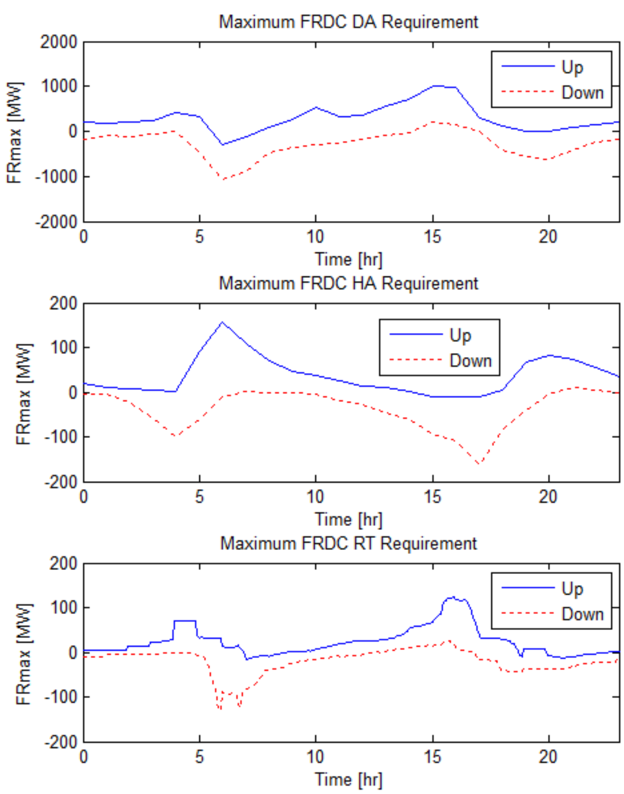

Fig. 2. FRDC maximum requirements in October

III. STUDY TEST BED

The system studied in this analysis is a modified version of the IEEE 118-bus test system [11]. The system generation portfolio and transmission capacities were updated to better reflect current, available operation cost data. Namely, some coal generation was converted to combined-cycle generation, and plant operating characteristics such as ramp rates were updated to better capture current generation plant flexibility.

Load, wind, and solar data were obtained based on available data for northern California from the Western Wind and Solar Integration Study Phase 2 report performed by NREL [12]. The characteristics of this new system are reflected in Table II.

The system was simulated for four weeks (one week each in January, April, July, and October) to capture the seasonal trends in load, wind, and solar profiles. To capture the effects of the ramp product, each week was simulated twice, once without the product to establish baseline results and once with it to measure its effects on efficiency and reliability metrics.

IV. SIMULATION RESULTS

A summary of the simulation results are shown in Table III. The production costs increase with the inclusion of the flexible ramping product, although only by a small percent. This is most likely attributable to increased curtailment in VG generation—i.e., including the flexible ramping product resulted in the commitment of excess thermal capacity that needed to remain online at the expense of curtailing VG output. Fig. 3 shows the unused, online thermal capacity during the week simulated in October. The inclusion of the flexible ramping product results in excess thermal capacity committed througout nearly the entire week of simulation. Similar trends can be observed in the other weeks as well.

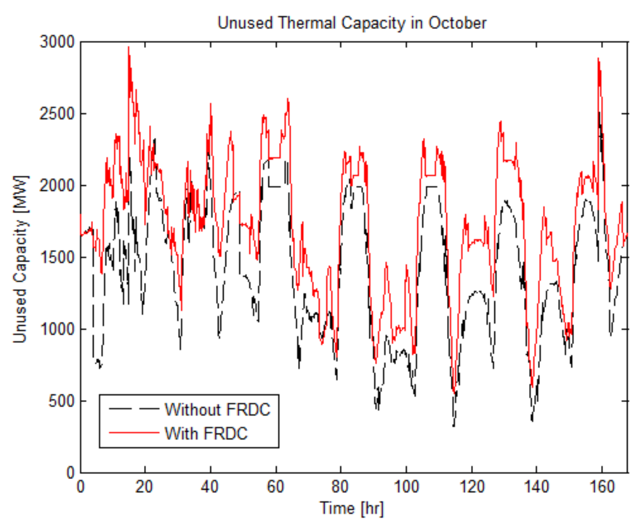

Fig. 3. Unused thermal capacity in October

The inclusion of the flexible ramping product helped to eliminate real-time scarcity events that were the result of insufficient ramping flexibility rather than energy shortage, and in some cases the number of scarcity events in the LMPs was reduced by as much as 96%. The flexible ramping product also helped to converge day-ahead and real-time prices. Fig. 4 shows the absolute difference between the load-weighted mean of the day-ahead and real-time LMPs. This helps shed some light on how well the day-ahead and real-time prices agree. Notice that among all weeks simulated, the differences between the day-ahead and real-time LMPs are reduced.

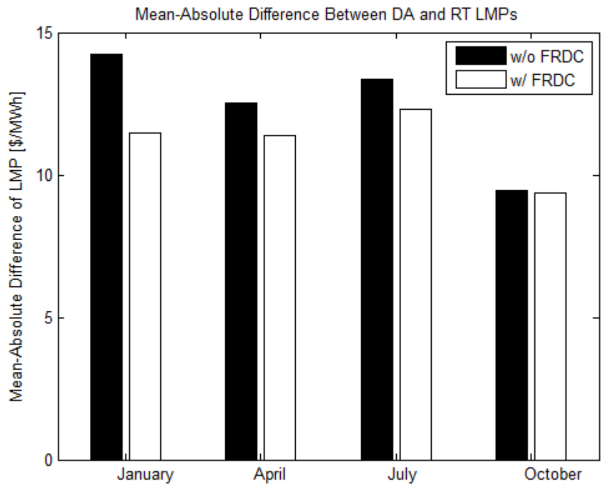

Fig. 4. Mean-absolute difference between day-ahead and real-time LMPs

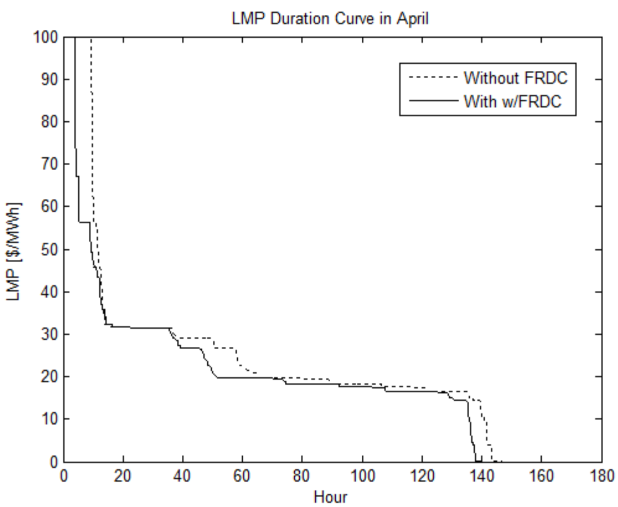

Fig. 5. LMP duration curve for April

The significant wind and solar curtailment occuring in the system leads to more instances with an LMP of 0 $/MWh. This is shown in the LMP duration curve in Fig. 5. The amount of VG curtailment is shown in Table IV. Notice that the amount of time with scarcity prices is noticably reduced and the amount of curtailment as shown by zero prices increases.

TABLE IV
VG CURTAILMENT IN GWH

	Without FRDC	With FRDC
January	13.19	15.02
April	28.18	32.38
July	11.19	11.35
October	20.85	25.43

Fig. 6 compares the LMPs among the cases to the flexible ramping product and the cases without flexible ramping product for all weeks simulated. If the inclusion of the flexible ramping product had no impact on LMPs, then all of the data points (LMPs) would fall on the diagonal (also plotted for reference). Any data point that falls below the diagonal implies that the flexible ramping product reduced the average LMP at that particular bus, and vice versa for all data points that fall above the diagonal. In general, the inclusion of the flexible ramping product increased the LMPs at nearly all buses for all weeks considered. In October, the opposite effect was observed. This could be due to the excess thermal generation committed during the valley times of the net load profile. Even though VG output was curtailed, thermal generators operating at their minimum output levels could not be turned off, thus resulting in significant excess thermal capacity online and the accumulation of positive ACE. Table V shows the direction of accumulated ACE for each case. Notice that including the flexibility reserve product increases the amount of ACE in the positive direction while reducing the amount of ACE in the negative direction.

TABLE V
BREAKDOWN OF ACCUMULATED ACE IN MWH

Case	Postive ACE	Negative ACE
Jan—Wihtout FRDC	1298	1060
Jan—With FRDC	1416	815
Apr—Without FRDC	1972	879
Apr—With FRDC	2074	844
Jul—Without FRDC	704	744
Jul—With FRDC	712	676
Oct—Without FRDC	1200	761
Oct—With FRDC	1465	707

TABLE III
NUMERICAL RESULTS

Case	Cost (million $)	Δ Cost	Number Of Price Spikes	Δ Number of Price Spikes	AACEE (MWh)	Δ AACEE	σ_{ACE}	Δ σ_{ACE}
January—Without FRDC	12.12	-0.06%	162	-96.3%	2357	-5.3%	26.7	-8.2%
January—With FRDC	12.11		6		2231		24.5	
April—Without FRDC	7.87	+4.4%	103	-75.8%	2851	+2.3%	35.3	-0.01%
April—With FRDC	8.22		25		2917		35.3	
July—Without FRDC	17.64	+0.12%	241	-58.1%	1447	-4.1%	16.9	-5.3%
July—With FRDC	17.66		101		1388		16.0	
October—Without FRDC	8.97	+3.8%	73	-89.0%	1960	+10.8%	23.8	+12.4%
October—With FRDC	9.31		8		2172		26.8	

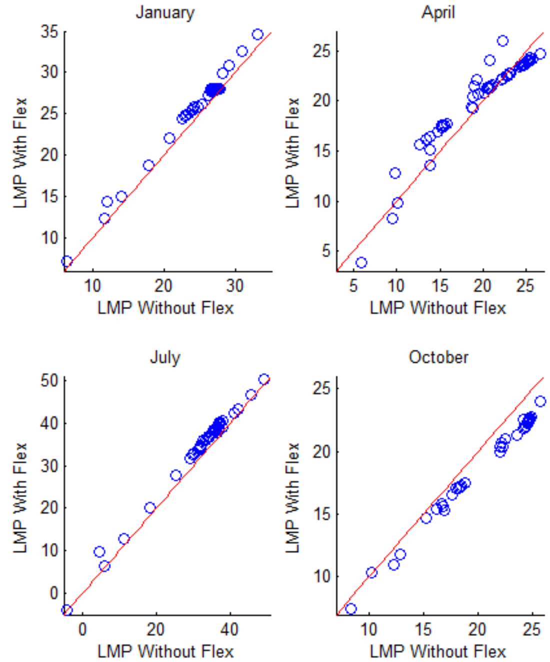

Fig. 6. Real-time LMP comparison among all cases

Figure 7 shows the available 5-minute ramping capacity in the January simulation. Notice that there is more ramping capacity available for the system that included the flexible ramping product. Similar behavior occurred thoughout the week and among all other weeks as well.

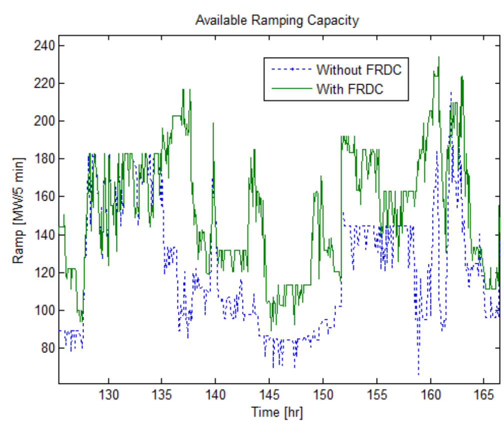

Fig. 7. Available ramping capacity for the block in January

V. Conclusion

This paper presents the analysis of a flexibility reserve ancillary service product and its impact on various efficiency and reliability metrics. The flexible ramping product increases production costs and ACE. This is most likely due to the flexible ramping product necessitating the commitment of excess thermal generation, which resulted in the curtailment of wind and solar resources. The commitment of excess thermal generation to meet additional flexibility requirements may result in the curtailment of wind and solar generation, particularly during the valley times in the net load profile, if it resulted in additional thermal capacity commitments during the same time frame. The loss of this zero-cost resource resulted in an increase in the total system production cost while forcing slower thermal units to be online, which resulted in the accumulation of more ACE. The inclusion of the ramping product helps converge the real-time LMPs. It also helps eliminate scarcity pricing events that occur as a result of insufficient ramping capacity.

VI. Acknowledgment

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