Quantifying the Potential Impacts of Flexibility Reserve on Power System Operations

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Quantifying the Potential Impacts of Flexibility Reserve on Power System Operations

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Abstract*—Power system operators schedule additional capacity above or below the amount required to meet the expected demand at any time interval to ensure reliable operation. This excess capacity is known as operating reserve. This reserve helps protect against the inherent variability and uncertainty found in the system. As more variable generation resources are connected to the system, the amount of variability and uncertainty is expected to increase. To hedge against this, new operating strategies are being explored. These strategies include developing additional ancillary services and modifying scheduling strategies. This paper presents the results of simulating an additional operating reserve product, referred to as "flexibility reserve," on the IEEE 118-bus test system, and it presents the operational implications on costs, reliability, and pricing that this additional operating reserve may produce.

Keywords-flexibility reserves, unit commitment, economic dispatch, variable generation, automatic generation control, mixed integer programming

I. Introduction

Given an ever-evolving electric power system, it may be necessary to revisit traditional operating strategies. With an increasing desire to reduce carbon emissions and other pollutants to mitigate global warming by incorporating zero-fuel technologies such as wind and solar power, and to help wean our dependency on fossil fuels, the integration of renewable energy resources in the power system is increasing. These resources provide cleaner energy, but their inherent operating characteristics present unique challenges because they are variable in nature. Variable generation (VG) can be defined as any generation resource that has an uncontrollable fuel source—for example, wind and solar photovoltaic (PV) generation. By increasing the amount of VG on the electric power system, the amount of variability and uncertainty on the electric power system may also increase. In this paper, variability is defined as the expected changes in both the upward and downward directions of power system conditions. Uncertainty is defined similarly as the unexpected changes in both directions of power system conditions [1]. This variability and uncertainty drive the need for operating reserves. Operating reserves can be defined as any real power capacity scheduled in one operational time frame and deployed in another. For example, to address the variability and uncertainty that occur within 5 minutes, the real-time economic dispatch solution may schedule a regulation reserve product. This regulation will then be deployed by the automatic generation control (AGC) to correct the real power imbalances that occur between economic dispatch solutions. As mentioned earlier, increasing the amount of VG on the power system may also increase the variability and uncertainty on the power system to a level that cannot be ignored [1]. If this threshold is reached, it may be necessary to revisit traditional operating strategies. One possible solution currently being investigated is adding a new ancillary reserve product and/or modifying the unit commitment formulation [2]-[10].

The authors of [2] present a mathematical formulation to be incorporated in the Midcontinent Independent System Operator's market-clearing optimizations to schedule an additional ancillary service product. This product is designed to ensure that there is enough ramping capacity available to the power system operator to maintain reliable operation. The ultimate objective is to increase the operational robustness of the system and reduce the frequency of short-term scarcity prices. Scarcity situations arise from an inability of the system to follow trends in the net load, which may result in infeasible dispatch solutions. This is becoming more challenging as increased VG increases system variability and uncertainty. The authors suspect that there may be an increase in system production costs, but the benefits of increased robustness and reduced scarcity prices are desirable consequences.

The authors of [4] propose enhancing the California Independent System Operator's market-clearing model to schedule additional capacity during market settlements. This capacity must be unloaded, ramp feasible, and dispatchable by the operators at any time in both the upward and downward directions. The additional capacity scheduled prior to the 5-minute economic dispatch is available for the binding dispatch interval and is not held in reserve. This method is expected to reduce the need to bias hour-ahead interchanges and reduce the number of scarcity pricing events that result from insufficient ramping rather than insufficient capacity.

The authors of [6] propose adding an ancillary service product based on the wind and solar forecast errors. This method calculates the wind and solar forecast errors independently. The geometric sum of these forecast errors covers a 70% confidence interval and creates the additional reserve requirements. The objective of this formulation is to create a dynamic, easily implementable reserve requirement that covers the additional uncertainty and variability introduced by both solar and wind resources. By incorporating accurate short-term solar forecasting techniques, the additional production costs associated with the variability and uncertainty of solar generators can be mitigated.

The authors of [7] propose imposing an additional ramping constraint in the unit commitment formulation. This constraint is based on the wind power generation spectral power density. The spectral density is incorporated into the unit commitment as a piecewise, convex function, and it is used to characterize the wind power variability. It should be noted that the flexibility of the generators is performed in the frequency domain.

The authors of [8] propose adding a reserve product that is a function of the probability of the occurrence of load shedding. The magnitude of the reserve requirement will depend on the amount of load-shedding incidents allowable per year. The probability of load shedding is calculated using the total system forecast error, which is a function of the load forecast error and the wind forecast error. Using this method, the authors determine that as wind power increases, there is a non-excessive increase in the amount of reserves that should be carried to maintain reliability.

The authors of [9] compare using a flexible ramping product in a deterministic economic dispatch solution to a stochastic economic dispatch solution. The authors note that a perfect stochastic economic dispatch formulation will not require an exogenous ramping reserve product, because considering multiple scenarios will best position the system to handle the uncertainty and variability present in the network. A deterministic economic dispatch with an additional ramping reserve product is considered and compared to a stochastic dispatch. The authors find that the addition of the "flexiramp" can improve system flexibility and costs; however, the results are directly affected by the amount of capacity acquired. This paper implements a specific additional reserve calculation methodology, as described in [10], to extract the operational implications of scheduling additional flexible capacity.

The rest of this paper is organized as follows: Section II details the methodology and model used to perform the simulations; Section III details the system used for the simulations; Section IV describes the results of the simulations; and Section V concludes the paper and proposes opportunities for future work.

II. Methodology and Model Description

A. FESTIV

The results of the simulations performed in this paper were produced using the Flexible Energy Scheduling Tool for Integrating Variable generation (FESTIV) created at the National Renewable Energy Laboratory. This is an inter-temporal, steady-state, power system operations model that co-optimizes dispatching of generators and scheduling of operating reserves. FESTIV simulates day-ahead operations via the day-ahead security constrained unit commitment, the real-time operations via the security-constrained unit commitment, and the real-time security-constrained economic dispatch (RTSCED). After the market clears, AGC is performed to correct the inter-RTSCED system-wide imbalance. All of the aforementioned sub-models contain fully configurable timing parameters, including model solve frequency, interval resolution, and optimization horizon length. All models are interconnected, such that the outputs of one model serve as the inputs for the next model to be solved in chronological order. FESTIV produces economic metrics (production cost) and reliability metrics in terms of area control error (ACE). In this manner, the trade-off between minimizing cost while maintaining system-wide real power balance can be explored. More details regarding this model can be found in [12].

This model uses MATLAB to control the flow of the simulation and to perform the AGC. The optimizations are formulated in GAMS and use CPLEX to solve the problems [13][14]. The unit commitment problems are formulated as mixed-integer linear programs, and the economic dispatch problem is formulated as a linear program. FESTIV produces several metrics that can help shed some light on the efficiency of flexibility reserves. By including the 4-second AGC sub-model, FESTIV can produce reliability metrics based on the relative imbalance occurring in the system. The first metric produced by FESTIV is the absolute area control error in energy (AACEE). This is the cumulative sum of the absolute value of ACE throughout the entire simulation, in megawatt hours. This metric provides insight into how the system is being balanced. The second metric produced FESTIV is the standard deviation of the raw ACE signal (σ_{ACE}). This metric shows the variability of the imbalance occurring in the system. FESTIV also produces the total production cost of the system during the simulation. The production costs are calculated based on the piecewise linear cost curves of the generators and the amount of energy they produce. In this simulation, wear-and-tear costs on the generators are ignored. FESTIV also produces system-wide locational marginal prices (LMPs). By examining the LMPs, the impact of this excess scheduled capacity on incentive structures can be examined.

B. Modelling Flexibility Reserve in FESTIV

FESTIV models reserve products with the following constraints. Equation 1 represents the reserve balance constraint. This constraint ensures that the amount of reserve scheduled is at least enough to fulfil the current requirement.

$$\sum_{t}\sum_{i} R_{i,t,\tau} \geq \Gamma_{t,\tau} \tag{1}$$

In (1), $R_{i,t,\tau}$ is the generator reserve schedule for generator i at time t for reserve type τ, and $\boldsymbol{\Gamma}_{t,\tau}$ is the reserve requirement for reserve type τ at time t. Equations 2 and 3 are used to set the maximum and minimum capability of a generator to provide reserves, respectively.

$$P_{i,t} + R_{i,t,\tau} \leq P_{max,i} \cdot I_{i,t} \tag{2}$$
$$P_{i,t} - R_{i,t,\tau} \geq P_{min,i} \cdot I_{i,t} \tag{3}$$

In (2) and (3), $P_{i,t}$ is the generation scheduled for generator i at time t, $R_{i,t,\tau}$ is the generator reserve schedule for generator i at time t for reserve type τ, $P_{max,i}$ is the maximum capacity of generator i, $P_{min,i}$ is the minimum capacity of generator i, and $I_{i,t}$ is the binary commitment variable of generator i at time t. Equation 2 is binding for all reserve types that are in the upward direction and require the generator to be online. Equation 3 is binding for all reserve types that are in the downward direction and require the generator to be online. The commitment variable is binary, in which a value of 1 indicates that the generator is online and a value of 0 indicates that the generator is offline. Equation 4 prohibits generators from providing reserves if the generator is currently within the start-up or shutdown trajectory.

$$R_{i,t,\tau} \leq P_{max,i} \cdot \left(1 - y_{i,t} - z_{i,t}\right) \tag{4}$$

In (4), $R_{i,t,\tau}$ is the generator reserve schedule for generator i at time t for reserve type τ, $P_{max,i}$ is the maximum generation capacity of generator i, $y_{i,t}$ is a binary variable indicating whether a generator is being turned on, and $z_{i,t}$ is a binary variable indicating whether a generator is being turned off. The start-up and shutdown indicators are mutually exclusive—i.e., a generator cannot be experiencing both a shutdown and a start-up during the same interval. Equation 5 is used to determine the amount of available capacity a generator has that can participate in reserve scheduling.

$$R_{i,t,\tau} \leq I_{i,t} \cdot RR_i \cdot RT_\tau + \left(1 - I_{i,t}\right) \cdot QSC_i \tag{5}$$

In (5), $R_{i,t,\tau}$ is the generator reserve schedule for generator i at time t for reserve type τ, $I_{i,t}$ is the binary commitment variable of generator i at time t, $RR_{i,t}$ is the megawatt-per-minute ramp rate of generator i, RT_τ is the reserve time of reserve product τ, and QSC_i is the amount of megawatts generator i can quickly provide if it is turned on. In this study, the quick-start capability of each generator is equal to its minimum generation capacity if that generator is able to reach that level typically within 10 or 30 minutes. Otherwise, the quick-start capacity is set to 0.

Flexibility reserve was modeled as described in [10]—i.e., as capacity scheduled in the unit commitment optimizations to be deployed in the economic dispatch. First, the flexibility reserve requirement from the additional wind generation on the system is calculated based on the wind forecast errors. This persistence forecast is used to characterize the uncertainty the system must be able to withstand due to wind. The forecast errors are then calculated by comparing the forecasted power to the realized power. These forecast errors are grouped according to the magnitude of the power associated with them. Then the flexibility reserve contribution due to wind is calculated for each group such that it covers 70% of forecast errors (i.e., 70% confidence interval). The solar forecast errors are calculated based on the persistence cloud cover forecasting technique described in [6] and [10]. This forecasting method is based on the solar power index, which is the ratio of the actual power produced by the generator to the clear-sky power of that generator at the same time interval. By using this technique, the short-term solar forecast can be calculated as follows:

$$P_F(t+\Delta t) = P(t) + SPI(t)[P_{CS}(t+\Delta t) - P_{CS}(t)] \tag{6}$$

In (6), P_F is the forecasted power, P is the realized power at time t, SPI is the solar power index at time t, and P_{CS} is the clear-sky power at time t. The clear-sky power is the amount of power the generator would have produced if there were no clouds in the sky. When the forecast is determined, the solar forecast error can then be calculated as follows:

$$P_\varepsilon = \Delta P(t) - P(t) - SPI(t)[\Delta P_{CS}(t)] \tag{7}$$

In (7), P_ε is the forecast error, P is the actual generation, ΔP and ΔP_{CS} represent the change in realized power and clear-sky power, respectively, between the current time interval and the following time interval, and SPI is the solar power index at time t. After the solar forecast errors are calculated, the flexibility reserve contribution due to solar power is calculated similarly to the wind contributions.

When the forecast errors due to solar and wind have been characterized, the total flexibility reserve requirement is calculated as follows:

$$R_{flex} = \sqrt{(\Gamma_{wind})^2 + (\Gamma_{solar})^2} \quad (8)$$

In (8), R_{flex} is the total flexibility reserve requirement, and $\boldsymbol{\Gamma}_{wind}$ and $\boldsymbol{\Gamma}_{solar}$ are the wind and solar contributions to the flex requirement, respectively. These requirements are calculated at both 5-minute and hourly temporal resolutions. Because of the unavailability of load forecasts, the contribution of load forecast errors was not included in this calculation, but it could be added to this requirement if the data were available.

The basic principle behind the use of flexibility reserves is the idea that the variability and uncertainty introduced by variable generators can be accounted for by scheduling additional generation capacity before the reserves are expected on the system. For example, to account for the variability and uncertainty that the wind and solar generators will introduce in the hour-ahead time frames, flexibility reserves can be scheduled in the day-ahead time frame. By performing this preemptive capacity scheduling, any unforeseen ramping event can be mitigated to a certain extent. Regarding FESTIV, the variability and uncertainty of the wind and solar generators in the hour-ahead unit commitment are accounted for in the day-ahead unit commitment. This is accomplished by co-optimizing the flexibility reserve product and energy in the day-ahead optimization. A similar procedure is done to account for the variability and uncertainty introduced at the 5-minute time resolutions by including the flexibility reserve product in the hour-ahead optimization. The flexibility reserve product is then removed from the dispatch optimization, because the subsequent AGC model addresses the variability and uncertainty using the previously scheduled regulation products rather than the flexibility reserve. This results in the release of the flexibility reserve capacity scheduled in the hour-ahead optimizations to address the variability and uncertainty occurring in the dispatch optimizations that are being solved every 5 minutes.

III. System Description

The simulations in this investigation were performed on a modified IEEE 118-bus test system. Solar and wind generators were added to the system based on the northern California data available at the time. The load data was also based on northern California. The data was obtained from the Western Wind and Solar Integration Study Phase 2 [10]. The system characteristics are shown in Table I.

Table I
Simulation System Characteristics

Number of Branches	186
Number of Thermal Generators	54
Solar Nameplate Capacity	907 MW
Average Solar Penetration	~ 9%
Wind Nameplate Capacity	358 MW
Average Wind Penetration	~ 4%

Table II
List of Simulated Scenarios

Scenario Name	Regulation Considered	Flexibility Considered
Neither		
Flex Only		X
Reg Only	X	
Reg and Flex	X	X

The above system was simulated for four different weeks—one in January, April, July, and October—in an attempt to capture seasonal trends in VG output and load profiles. Each week was then simulated for four scenarios (see Table II). Wind power was forecasted using a short-term persistence forecast. Solar power was forecasted using a persistence cloud-cover forecasting method described in [6]. Each case was simulated with contingency spin and contingency non-spin reserves. Regulation up, regulation down, flex up, and flex down reserves were simulated when appropriate. Spin and non-spin reserves were taken as 3% of the load. Regulation reserves were taken as 1% of the load based on the base requirement for regulation reserve as determined by the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee [11].

IV. Results

The system described in Section III was first simulated without regulation reserve. This was done to obtain an upper bound on the impacts of flexibility reserve on system operations by minimizing the number of independent variables. Then the same simulations were performed including regulation reserve to more accurately capture the way power systems operate today.

A. Results Without Regulation Reserve

Numerical results from the simulations are presented in Table III. These results compare weekly simulations with and without flexibility reserve. Regulation reserve was not included in either case. The additional ancillary service had negligible impacts on system production costs. One of the potential benefits of this additional ancillary service mentioned in [2] and [4] is the reduction in scarcity pricing events. Simulations corroborated this behavior, sometimes reducing the number of scarcity pricing events—energy prices exceeding $1,000/MWh—by more than 80%. Another interesting result is that the additional flexibility reserve had negligible impacts on system reliability in terms of imbalance. The last four columns in Table III describe the reliability metrics produced by the simulations. As shown in Table III, both of these metrics remained relatively unchanged when the flexibility reserve was included in the simulations.

The plot shown in Fig. 1 corresponds to an hour from the July simulations. During those hours, the additional flexibility reserve was able to eliminate seven scarcity pricing events. It is evident that the case with the flexibility reserve product had additional unused steam generator ramping capacity, because it committed an extra steam generator during this time period; thus, this case was better situated to handle the change in load and contingency reserve requirements. Because less capacity was committed in the case without flexibility, more combustion turbines were utilized.

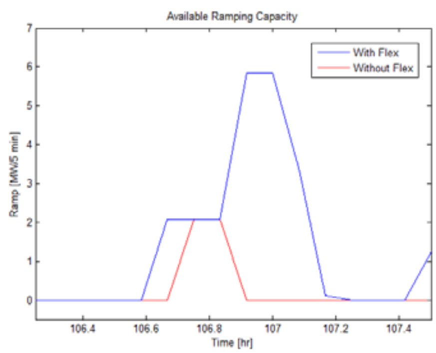

Fig. 1. Available steam generator ramp capacity

The amount of utilized combustion turbines decreased with the inclusion of the flexibility reserve product in all scenarios but the week in April—i.e., on average, April experienced the lowest demand compared to the other months. This is shown in Table IV. As a result, the amount of generation that the steam generators provided increased in cases with large load. However, during low loading conditions, the combustion turbines were still utilized.

TABLE IV
AMOUNT OF UTILIZED GENERATION FROM COMBUSTION TURBINES

Case	CT [MWh]	Δ CT
Jan – Neither	3166	-9.6 %
Jan – With Flex	2861	
April – Neither	611	+0.7 %
April – With Flex	615	
July – Neither	932	-9.7 %
July – With Flex	842	
Oct – Neither	818	-1.0 %
Oct – With Flex	810	

By including the flexibility reserve product in the optimization, more steam generation was committed and available for dispatch. This was true particularly during times of peak demand. The available steam capacity during the April simulations for the cases with and without the flexibility reserve product is shown in Fig. 2. Notice that during times of peak demand, the scenario with the flexibility reserve had more available steam capacity.

B. Results Including Regulation Reserves

Traditional system operations include some form of regulation that allows the operator to balance the real-time demand with generation. To capture the implication of flexibility reserve on this type of system, the previous simulations were repeated on a system that included a regulation product. The regulation requirement was taken as 1% of the system load. The regulation reserve was scheduled in the economic dispatch sub-model and deployed in the AGC sub-model. The system remained otherwise unchanged.

The simulation was performed for the same week, and the results are shown in Table V. The inclusion of flexibility reserve had similar negligible impacts on ACE on a system with regulation as it did on a system without

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 – Neither	4.065	-0.13%	57	-74%	1168.43	-0.02%	10.17	+0.14%
January – Flex Only	4.059		15		1168.21		10.19	
April – Neither	3.261	+0.06%	28	-75%	1460.21	+0.07%	11.87	+0.03%
April – Flex Only	3.263		7		1461.24		11.87	
July – Neither	5.436	+0.04%	28	-29%	1369.04	0.00%	9.93	+0.25%
July – Flex Only	5.438		20		1369.03		9.95	
October – Neither	3.635	+0.13%	23	-87%	1286.48	+0.10%	10.55	+0.08%
October – Flex Only	3.640		3		1287.77		10.56	

regulation. The difference between the reliability metrics in the cases with and without regulation is quite significant, but this is expected because the purpose of regulation is to correct the ACE. However, by including flexibility reserve, there are negligible impacts on the ACE reliability metrics; see Table V.

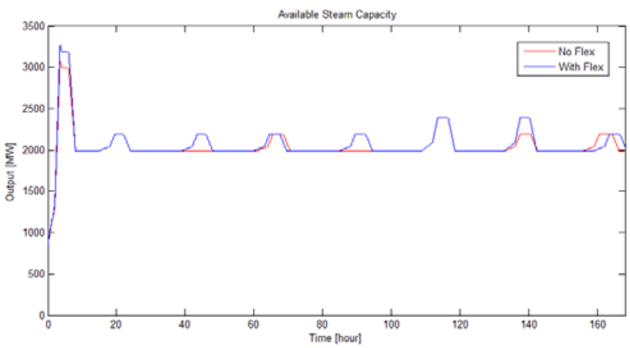

Fig. 2. Available steam capacity during April

As previously mentioned, one of the benefits of the flexibility reserve product is to help reduce the number of scarcity events that occur as a result of insufficient ramping capacity in the system. By including regulation reserve in the system, extra capacity is already scheduled. As a result, there are significant opportunities to reduce the flex reserve requirement. These results are shown in Table VI. An opportunity to reduce the flexibility reserve requirement is defined as an interval in which there is not a scarcity event occurring at that time and there is excess capacity in the system. Scarcity intervals are defined as intervals in which scarcity prices (i.e., prices greater than $1,000/MWh) are realized in the real-time dispatch. An opportunity to increase the flexibility reserve requirement is defined as an interval in which there is a scarcity event and the price for the flexibility reserve is $0/MW-h—i.e., there is no lost opportunity cost for providing flexibility reserve to commit additional capacity.

TABLE V

OPPORTUNITIES TO MODIFY THE FLEXIBILITY RESERVE REQUIREMENT

Case	# Intervals to Increase	# Intervals to Decrease	% of Total Intervals
Jan – Reg Only Jan – Reg and Flex	4	438	65.8%
Apr – Reg Only Apr – Reg and Flex	0	208	31.0%
July – Reg Only July – Reg and Flex	1	443	65.9%
Oct – Reg Only Oct – Reg and Flex	1	285	42.4%

For example, in January there were four 5-minute intervals in which the flexibility reserve requirement could be increased when regulation reserves were included, and there were 438 intervals in which it could be decreased. These opportunities represented 65.8% of the total intervals considered in January. As shown in Table VI, there may be substantial opportunities to modify the flexibility reserve requirement for the selected method, mostly by reduction, when regulation reserve is included in the system.

In the simulations with regulation, the inclusion of the flexibility reserve product also reduced the utilization of expensive combustion turbines. Similar to the cases that did not incorporate regulation reserves, the curtailed use of expensive combustion generation led to the utilization of more steam generators. The reduction in the utilization of combustion turbine generation was greater when compared to the scenarios that did not include regulation; see Table IV. This could be because some of the steam generators provided regulation; therefore, several steam generators had to be committed and utilized throughout the simulation period and helped minimize the need for combustion turbines. The total amount of combustion turbine production is shown in Table VII.

TABLE VI

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 – Reg Only	4.065	-0.02%	43	-58%	191.81	-5.0%	2.40	-5.8%
January – Reg and Flex	4.064		18		182.15		2.26	
April – Reg Only	3.265	+0.11%	17	-77%	387.56	-1.2%	4.32	-0.5%
April – Reg and Flex	3.268		4		382.94		4.30	
July – Reg Only	5.446	-0.09%	28	-46%	129.37	-2.4%	1.94	-5.9%
July – Reg and Flex	5.441		15		126.29		1.82	
October – Reg Only	3.641	+0.03%	28	-82%	270.45	-2.4%	3.04	-1.2%
October – Reg and Flex	3.642		5		264.03		3.00	

TABLE VII
AMOUNT OF UTILIZED GENERATION FROM COMBUSTION TURBINES WITH REGULATION

Case	CT [MWh]	Δ CT
January – Reg Only	2885	-3.1%
January – Reg and Flex	2796	
April – Reg Only	755	-13.4%
April – Reg and Flex	654	
July – Reg Only	1207	-26.4%
July – Reg and Flex	888	
October – Reg Only	924	-5.0%
October – Reg and Flex	878	

As mentioned earlier, a benefit of flexibility reserve is the potential reduction in scarcity events. This benefit holds true in the cases that include regulation. For example, the real-time prices and ACE for the January scenario with regulation are shown in Fig. 3 and Fig. 4.

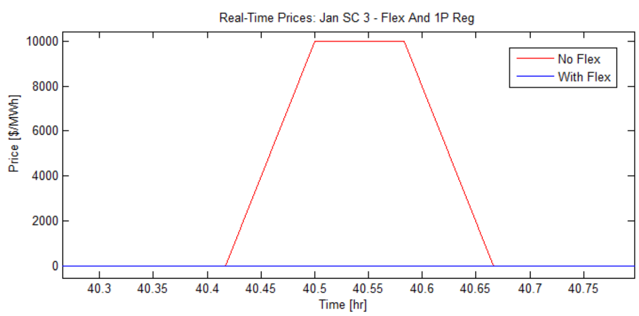

Fig. 3. Real-time prices in January

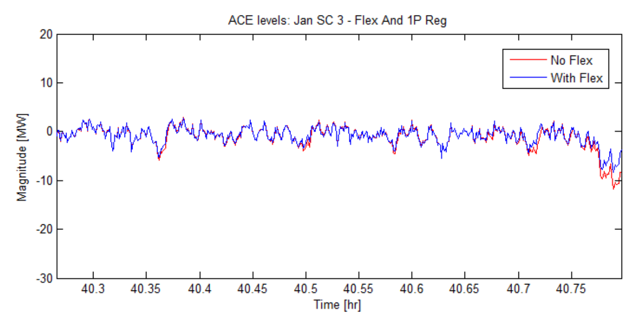

Fig. 4. ACE in January

Notice that when scarcity pricing was observed, there was no appreciable imbalance in the system. This was true for both the simulation with the flexibility reserve and the system without the flexibility reserve. This suggests that the penalty pricing was not a result of insufficient generation capacity or potential for a reliability event. By including the flexibility reserve, the system that had more ramping capacity online was able to avoid the scarcity price. Fig. 5 shows the amount of available ramping capacity on the system during this time.

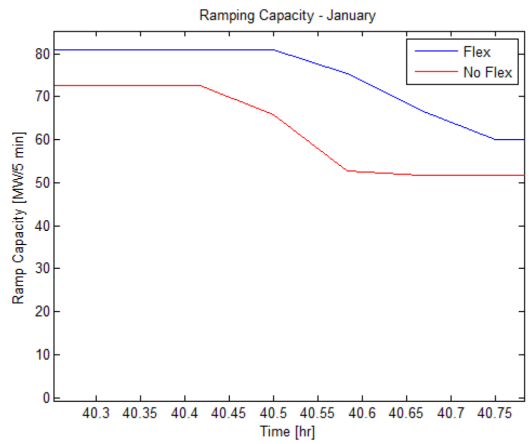

Fig. 5. Ramp capacity available in January

V. CONCLUSION

The analysis in this paper sheds some light on the operational implications of emerging electricity market solutions. Several independent system operators, namely the California Independent System Operator and the Midwest Independent System Operator, are considering additional ancillary service products to help mitigate the additional system-wide variability and uncertainty that will be introduced with increased penetrations of VG. The observations that are quantified in this paper are summarized below:

- The inclusion of the additional ancillary service, referred to as flexibility reserve in this paper, reduced the number of scarcity events, mostly those caused by insufficient ramping capacity, throughout the study period. Sometimes this reduction was as significant as up to 87% percent.
- The reduction in scarcity events may impact generator revenue. If generators receive payments based on the scarcity price, their payments will decrease if the number of scarcity events decreases.
- The inclusion of the flexibility reserve product resulted in a reduction in the commitment and dispatch of combustion turbines. Sometimes this reduction was as high as 26%.
- The inclusion of the flexibility reserve product had negligible effects on reliability metrics. These metrics included the AACEE, which is a measure of the total magnitude of accumulated imbalances throughout the study period, and the standard deviation of the ACE.
- The inclusion of the flexibility reserve product resulted in additional ramping capacity and available generation on the system, particularly during times of peak load. This additional capacity was sometimes enough to eliminate a scarcity pricing event that was not caused by insufficient generator commitments.

- The addition of regulation with the flexibility reserve product resulted in several opportunities to modify the flexibility reserve requirement. Sometimes the number of opportunities to modify the flexibility reserve requirement reached more than 75%. Most of the opportunities to modify the flexibility reserve were opportunities to reduce it. This means that by including the regulation reserve, there is already some additional capacity on the system. As a result, the amount of additional capacity committed due to flexibility reserve reaches a threshold at which the benefit it provides is reduced.

Increasing VG penetrations will undoubtedly require modifying traditional power systems operations. By investigating potential solutions, a better understanding of their operational implications can lead to obtaining the best solution. Now that studying some implications of additional ancillary service products has been performed, a direct comparison among the advantages and disadvantages of different types of additional ancillary service products and different calculations used to determine the requirements should be performed so that the best solution can be adopted.

VI. References

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