ARTICLE IN PRESS

Renewable and Sustainable Energy Reviews xxx (xxxx) xxx–xxx

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

Assessing environmental, economic, and reliability impacts of flexible ramp products in MISO's electricity market

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ARTICLE INFO

Keywords:
Ramp Capability products
Renewable power integration
Unit commitment and economic dispatch
Market clearing algorithms
Uncertainty analysis in electric power markets

ABSTRACT

Increased variability and uncertainty of net electrical load due to high penetration of wind and solar power augments the need for dispatching conventional generators with sufficient ramping capability (RC) needed to balance demand with supply. Having sufficient RC reduces the need of last minute dispatch schedule modifications which cause cost, reliability and environmental outcomes that reduce the benefits of renewables. The Midcontinent Independent System Operator (MISO), has modified its Unit Commitment and Economic Dispatch algorithms to account for the economic value of provisioning adequate RC levels. This paper explores the outcomes of this modified market-clearing process by simulating 10-minute operations of a scaled MISO test system, for three representative months under low and high wind penetration scenarios. Changes in system performance are quantified by comparing system costs, scarcity events/pricing, energy prices, generation-fuel mix, wind-power curtailment, and CO_2 emissions between the conventional market-clearing algorithm and one with flexible RC products. Results indicate that adding RC products lowers CO_2 emissions and system costs, facilitates wind integration, and improves reliability. These benefits are robust to changes in the market clearing algorithm parameters such as over/under generation penalties and reserve scarcity prices.

1. Introduction

Higher penetration of Variable Energy Resources (VERs) such as solar and wind is expected to have numerous environmental benefits, but it also increases the variability and uncertainty of net electrical load. This augments the need for dispatching resources with sufficient ramping capability (RC) to adjust their power output and help strike a balance between demand and supply. Last minute changes in the dispatch of conventional generators to respond to RC shortages may result in cost, reliability and environmental outcomes that reduce the benefits of increased penetration of VERs. For example, in the Midcontinent Independent System Operator (MISO) - serving 42 million people and containing over 175 GW of total generation capacity including 13 GW of wind [1,2], forecasted shortages of RC force operators to dispatch fast-ramping but expensive combustion turbines or make other out-of-market adjustments to the optimal schedules suggested by the UC and ED algorithms.

While necessary from a reliability standpoint, out-of-market adjustments may result in higher emissions relative to the optimal dispatch, because fast-ramping combustion turbines are typically less efficient than other generators (see SI table S8). Also, these adjustments tend to be uneconomic because lack of RC may reduce reserve levels below the target, triggering the process of "scarcity pricing" which sets the market clearing prices at high levels. Further, out of market adjustments hide the magnitude and severity of the problem and, by neglecting to provide transparent price signals to market participants, do not contribute to its prevention [3].

Although ramping needs may also be caused by changes in load, imports and exports, and deviations from instructed levels of generation by dispatchable units, VER intermittency is a big contributor. As renewable penetration increases the issue will only be exacerbated [3,4], and hence, U.S. ISOs with increased penetration of VERs are exploring alternate scheduling processes. A comprehensive review of approaches to enhance power grid operational flexibility is included in Wang and Hodge [5].

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http://dx.doi.org/10.1016/j.rser.2017.06.037
Received 25 July 2016; Received in revised form 16 February 2017; Accepted 16 June 2017
1364-0321/

Please cite this article as: Cornelius, A., Renewable and Sustainable Energy Reviews (2017), http://dx.doi.org/10.1016/j.rser.2017.06.037

In 2016, MISO implemented a modified UC/ED algorithm that directly accounts for the economic value of provisioning an adequate level of RC as represented by a demand curve of ramping. In the context of these modifications two new "products" arise: Up Ramp Capability (URC) and Down Ramp Capability (DRC). URC and DRC are different from other ancillary services in that generators will not separately offer RC. By submitting an offer to provide energy in the day-ahead market, they offer to provide whatever combination of energy and RC the dispatch model finds most cost-effective to the system. Generators selected to provide RC will be paid based on their opportunity cost of doing so. Similar to reserves, the real-time dispatch may or may not deploy the RC procured in prior intervals [3].

1.1. Objectives of this study

The objectives of this study are: (a) to assess the environmental, economic, and reliability impacts of introducing flexible RC products in MISO by simulating the market clearing process of a scaled system with and without these products, and (b) to explore the conditions affecting the performance of RC products under different product design parameters and MISO system assumptions.

1.2. Literature review

MISO's plan is presented in two pieces by Navid and Rosenwald [3,6], in a cost-benefit analysis by Navid et al. [7], and in a proposal that has been approved by the Federal Energy Regulatory Commission (FERC) [8,9]. The California Independent System Operator filed a similar proposal [10] that was also approved by FERC [11,12]. The estimates of potential benefits of RC products are based on small test systems containing at most five generating units [6,10], or containing the entire power generation fleet [3,7] but for 4 sample days from which annual impacts are extrapolated.

In general, these studies indicate that the RC products implemented in MISO would result in net savings. Although small increases in market clearing prices are found in some intervals in order to procure the RC, overall system costs are lowered due to a reduction in scarcity pricing and uplift payments. Estimates of MISO's net savings due to reductions in production costs, unserved reserves, and combustion turbine commitments are in the range of $3.8–5.4 million/year under current conditions with additional smaller savings expected from avoiding penalty prices caused by transmission constraint violations [3,6,7].

These studies also find that RC products would improve system reliability and result in increased price transparency when compared to existing ISO practices. The CAISO analysis shows that even after incorporating multi-period look-ahead optimization to clear the real-time market, and even under the conditions of perfect foresight of ramping need, introducing RC products has the benefit of separating energy prices from RC prices resulting in less volatile and more transparent prices [10].

Although MISO and CAISO have moved ahead with the introduction of RC products as a relatively minor modification to the current deterministic market-clearing practices, the academic literature has studied RC as a substitute or complement to alternative market clearing designs. Wang and Hobbs [13] compare costs and benefits of a deterministic dispatch model that includes the ramp product (much like MISO's proposal) both to the standard dispatch model and to the stochastic ideal. They find the benefits of RC products are heavily dependent on the chosen values of ramp capability requirements and other parameters. Khodayar et al. [14] also look at RC products in the context of a stochastic unit commitment and propose a bid-based RC market approach in which generators offer their ramp-capability as a function of RC price (i.e., elastic ramp service). Ela and O'Malley [15] consider a case where there is perfect foresight of a system's ramping needs in future periods and compare Ramp Capability Requirement Constraints, with Time-Coupled Multi-Period Market Models in their ability to meet expected variability. They find that including ramp-capability constraints is likely to result in the same reliability and avoidance of price-spikes as the time-coupled multi-period market models, and propose a market design that combines the two approaches to reduce system costs. Wu et al. [16] propose a risk-limiting economic dispatch scheme to optimize the dispatch and provision of RC products relative to the standard deterministic economic dispatch that is currently in place in U.S. markets.

Other authors have proposed RC market designs that allow wind power generators [17,18] and energy storage systems to provide ramp capability [19] while others have examined the outcomes of bid-based RC products that consider market participants' strategic behavior [20].

While previous assessments of RC products in the context of existing market designs or potential new approaches have reviewed the effects of RC products on economic and reliability outcomes, they have ignored environmental effects. The purpose of this paper is to fill this gap and explore the environmental impacts, along with the economic and reliability costs and benefits of RC products.

1.3. Primary contributions

Our analysis differs from previous studies in: a) the estimation of changes in CO_2 emissions and wind curtailment, b) the detail of representation of MISO's power generation fleet, c) the length and time-resolution of the period of analysis, d) the consideration of high wind penetration scenarios, e) the estimation of uncertainty margins for determining RC products as a function of factors known to affect net load, and f) the exploration of performance of RC products under different product design and MISO system parameters.

We simulate day-ahead and real-time operations to estimate changes in generation fuel mix, wind-power curtailment, generator start-ups, CO_2 emissions, total system costs (including the costs of reserves and payments for RC products), scarcity events and pricing, and overall energy prices between the standard market clearing process (StdMC) and a market clearing process that includes ramp capability products (RCMC).

2. Materials and methods

Power system simulations are conducted during 3 representative months, according to hourly day-ahead UC and ED algorithms and a 10-minute real-time ED algorithm. We set up two systems that each have 6% of MISO's load and generation capacity with roughly the same proportion of coal, natural gas, and nuclear power as MISO in 2009 [21] but differ in their levels of wind penetration. The low wind penetration system (LW) has wind nameplate capacity equal to 7% of total generation capacity (the same proportion as MISO had in 2009); the high wind penetration system (HW) has 19% while holding all other generation types constant. Other fuel sources such as hydro, diesel, and demand resources represent less than 5% of MISO generating capacity and are left out of the analysis. Details on the test system and other assumptions and methods are in Sections 1 and 2 of the supporting information (SI) document.

The systems have 44 coal and gas generators selected from MISO's fleet –see Section 2 of SI- using a k-means clustering analysis. Cost and performance data are taken from various sources. Name plate capacity, average heat rates, and average CO_2 emissions are taken from eGRID [21] and EIA Form 923 [22]. Data sources for required minimum generation levels and maximum ramp-rates for each power generator, minimum up and down times, no load costs, start-up heat rates, and start-up emissions are listed in Section 3 of the SI and include references [23–29]. As explained in the SI, start-up heat rates and corresponding emissions are estimated based on generator type, size, and nominal heat rate.

We use EIA-reported average prices of coal and natural gas for electric power from the five-year period ending in March 2014 [30] and eGRID heat rate data to estimate generator fuel cost, which we assume to be the only marginal cost. Spinning reserve offers are assumed to be 20% of energy marginal cost.

The wind generators included in both the LW and HW systems correspond to modeled wind sites in the MISO states selected from EWITS [31] (see Section 4 of SI). Because EWITS data is only available in 10 minute intervals, this is the granularity used for real-time model runs. EWITS-simulated day-ahead hourly wind generation forecasts are used to simulate the day-ahead market. The wind power forecasts for the next 10-minute interval necessary to simulate the real time markets are generated assuming a percent forecast error independently and identically distributed (i.i.d.) as a normal distribution with a mean of zero and a standard deviation of 4%. MISO reports a 5-minute-ahead wind forecast error standard deviation of 3% [3]. We assume a higher standard deviation for the 10-minute forecast to account for the higher variation in forecast accuracy associated with the increased length of the forecast period.

Load data for each 10-minute interval are obtained by taking the averages of two consecutive 5-minute intervals of the real time load for January, April and July of 2010, collected and published by LCG Consulting [32] -see Section 5 of SI. Day-ahead and real-time load forecasts are simulated assuming the percent forecast error is normally distributed with a zero mean and a standard deviation of 1% for the day-ahead, and 0.2% for 10-min intervals (consistent with the 1% day-ahead and 0.12% 5-minute-ahead standard deviations of load forecasts in MISO [3]) -see Section 6 of SI.

Other parameters necessary for the StdMC and RCMC models are taken from MISO documents; spinning reserves must be capable of being deployed within 10 minutes with a penalty of \$1100/MWh if there is a shortage; there is a penalty of \$3500/MWh for under-generation (VOLL) and \$500/MWh for over-generation [33]; and the demand curve for URC and DRC is set as a fixed value of \$10/MWh that acts as a price cap for both products [3] (see Section 7 of SI). A sensitivity analysis varying these parameters is reported in Section 3.6.

3. Theory

Three baseline models represent StdMC: day-ahead unit commitment (B-DAUC), day-ahead economic dispatch (B-DAED), and real-time economic dispatch (B-RTED). Model formulations are presented in section 10 of the SI. The models assume a competitive market where all generators bid their marginal costs. A single iteration of the B-DAUC/B-DAED model uses day-ahead forecasts of load and wind generation to produce co-optimized hourly market prices and commitment, generation and reserve schedules over a 24-hour period. Inputs to the B-RTED model are the commitment schedule from the day-ahead market and actual load and wind power levels; outputs are least-cost generation and reserve schedules and market prices for a single 10-minute interval (without considering future forecasts). A full one-day simulation consists of one iteration of each of B-DAUC and B-DAED and 144 (i.e. 6 intervals/hour × 24 hours) runs of B-RTED.

The RCMC process is represented with a second set of models that include the RC products. Fig. 1 summarizes the differences between the StdMC and RCMC operation of the Unit Commitment and Economic Dispatch model.

The two key inputs to the RCMC model, the up and down capability requirements $\mathrm{RCUpDCMax}_t$ and $\mathrm{RCDownDCMax}_t$ (called URC target and DRC target in Fig. 1) are set in the real time as:

$$\mathrm{RCUpDC\,Max}_t = \max\{\mathrm{FNetLoad}_{t+1} - \mathrm{ActNetLoad}_t + \mathrm{RTUncert}_{\mathrm{up}_{t+1}}, 0\} \tag{1}$$

$$\mathrm{RCDownDC\,Max}_t = \max\{\mathrm{ActNetLoad}_t - \mathrm{FNetLoad}_{t+1} + \mathrm{RTUncert}_{\mathrm{down}_{t+1}}, 0\} \tag{2}$$

And in the day-ahead as:

$$\mathrm{RCUpDC\,Max}_t = \max\left\{(\mathrm{FNetLoad}_{t+1} - \mathrm{FNetLoad}_t) \times \frac{\mathrm{RampResponseTime}}{\mathrm{IntLength}} + \mathrm{DAUncert}_{\mathrm{up}_t}, 0\right\} \tag{3}$$

$$\mathrm{RCDownDC\,Max}_t = \max\left\{(\mathrm{FNetLoad}_t - \mathrm{FNetLoad}_{t+1}) \times \frac{\mathrm{RampResponseTime}}{\mathrm{IntLength}} + \mathrm{DAUncert}_{\mathrm{down}_t}, 0\right\} \tag{4}$$

Where:

$\mathrm{RampResponseTime} = \mathrm{Real\ Time\ IntLength} = 10\mathrm{minutes}$

$\mathrm{Day\ Ahead\ IntLength} = 60\mathrm{minutes}$

$\mathrm{RCUpDCMax}_t$	The targeted amount of up-ramp capability (URC) in interval t [MW]
$\mathrm{RCDownDCMax}_t$	The targeted amount of down-ramp capability (DRC) in interval t[MW]
$\mathrm{FNetLoad}_{t+1}$	Forecasted Net Load at time t for period t+1 (Forecasted Demand - Forecasted Variable Generation)
$\mathrm{ActNetLoad}_t$	Actual Net Load at time t (Actual Demand - Actual Variable Generation)
$\mathrm{RTUncert}_{\mathrm{up}_{t+1}}$	Estimated upward uncertainty at time t of forecasted net load for period t+1
$\mathrm{RTUncert}_{\mathrm{down}_{t+1}}$	Estimated downward uncertainty at time t of forecasted net load for period t+1
$\mathrm{DAUncert}_{\mathrm{up}_t}$	Estimated RT upward uncertainty during interval t
$\mathrm{DAUncert}_{\mathrm{down}_t}$	Estimated RT downward uncertainty during interval t
RampResponseTime	Response time for ramp capability (used in day-ahead models) [minutes]
IntLength	Length of interval [minutes]

Refer to section 8 of the SI for details of the calculation of up and down capability requirements. The difference in the real-time and day-ahead RC formulations (see details in sections 9 and 10 of SI) stems from their differing time-granularity (i.e. 10 minute intervals for the real-time and 60 minute intervals for the day-ahead). The real-time model procures RC to ensure that it can meet the forecast and uncertainty for the following real-time interval. The day-ahead model, on the other hand, procures RC to ensure that there is sufficient flexibility within each day-ahead interval to manage real-time variability and uncertainty that will occur when the generating units committed in the day-ahead market are used to supply actual load in the more volatile real-time market with higher time resolution.

The uncertainty estimates depend on the time-regime T to which the time interval belongs. We partition the historical time series of ActNetLoad and $\mathrm{FNetLoad}_t$ into 24 different time-regimes T corresponding to three seasons (winter, spring/fall, and summer), four time-of-day periods (morning, midday, evening, and night) and two day types (weekday and weekend) and estimate uncertainty as follows:

$$\mathrm{RTUncert}_{\mathrm{up}_{t+1}} = \mathrm{UncUpPct}_T \times \mathrm{FNetLoad}_{t+1} \tag{5}$$

$$\mathrm{RTUncert}_{\mathrm{down}_{t+1}} = \mathrm{UncDownPct}_T \times \mathrm{FNetLoad}_{t+1} \tag{6}$$

$$\mathrm{DAUncert}_{\mathrm{up}_t} = \mathrm{UncUpPct}_T \times \mathrm{FNetLoad}_t \tag{7}$$

$$\mathrm{DAUncert}_{\mathrm{down}_t} = \mathrm{UncDownPct}_T \times \mathrm{FNetLoad}_t \tag{8}$$

$$\mathrm{UncUpPct}_T = \mathrm{AvgErrorPct}_T + 2 \times \mathrm{SDErrorPct}_T \tag{9}$$

$$\mathrm{UncDownPct}_T = \mathrm{AvgErrorPct}_T - 2 \times \mathrm{SDErrorPct}_T \tag{10}$$

Where $\mathrm{AvgErrorPct}_T$ and $\mathrm{SDErrorPct}_T$ are the average and standard

Day-ahead Unit Commitment Model

Planning Period: 24 hours
Interval: 1 hour
Minimize:
Generation Costs + Spinning Reserve Costs + Startup Costs + No Load Costs + OverGeneration Penalty + UnderGeneration Penalty + Reserve Scarcity Penalty ***– Benefits of Procured URC – Benefits of Procured DRC***
Subject to: *for all time periods*
- Energy Generated = Forecasted Net Load
- Reserves Available >= Reserves Required
- ***System URC Procured <= URC Target***
- ***System DRC Procured <= DRC Target***
- ***Sum of Generator URC >= System URC Procured***
- ***Sum of Generator DRC >= System DRC Procured***

Generator constraints *for all time periods and generators*
- Ramp rates (***Accounting for URC and DRC***)
- Min up/down time
- Min/Max Generation (***Including URC and DRC***)

Output:
- Planned Hourly Day-ahead Generator Schedules for:
  - Commitment (on/off)
  - Energy Produced
  - Spinning Reserves Provided
  - ***URC/DRC***

Real Time Economic Dispatch Model

Planning Period: 10 Minutes
Interval: 10 Minutes
Minimize:
Generation Costs + Spinning Reserve Costs + OverGeneration Penalty + UnderGeneration Penalty +Reserve Scarcity Penalty ***– Benefits of Procured URC – Benefits of Procured DRC***
Subject to:
- Energy Generated = Actual Net Load
- Reserves Available >= Reserves Required
- ***System URC Procured <= URC Target***
- ***System DRC Procured <= DRC Target***
- ***Sum of Generator URC >= System URC Procured***
- ***Sum of Generator DRC >= System DRC Procured***

Generator Parameters not violated
- Ramp rates ***(Accounting for URC and DRC)***
- Min up/down time
- Min/Max Generation ***(Accounting for URC and DRC)***

Output:
- Generator Dispatch levels for:
  - Energy Produced
  - Spinning Reserves Provided
  - ***URC/DRC***
- Market Clearing Price for
  - Energy
  - Spinning Reserves
  - ***URC/DRC***

Fig. 1. Problem formulation for Day Ahead Unit Commitment and Real Time Economic Dispatch models under RCMC. Changes made to the models corresponding to StdMC in order to account for URC/DRC products are in italics and are underlined.

deviation of a time series of $\mathrm{ErrorPct}_t$ values estimated from the time-series of RT $\mathrm{ActNetLoad}_t$ and RT $\mathrm{FNetLoad}_t$ as:

$$\mathrm{ErrorPct}_{t+1} = (\mathrm{ActNetLoad}_{t+1} - \mathrm{FNetLoad}_{t+1})/\mathrm{FNetLoad}_{t+1} \quad (11)$$

Set in this way, $\mathrm{RCUpDCMax}_t$ and $\mathrm{RCDownDCMax}_t$ are upper bounds of ~95% confidence intervals for ramp requirements, assuming they follow a normal probability distribution (see Section 8 of SI).

Both sets of models are used independently to simulate operations of the system for three one-month intervals representing three seasonal load profiles (winter, spring/fall, and summer) and two wind penetration scenarios.

Environmental impacts of the introduction of RC products are assessed by looking at changes in wind curtailment and total CO_2 emissions as a result of variations in fuel type and generator start-ups. An assessment of reliability outcomes is performed by calculating the occurrences and amount of energy and reserve shortages. To examine economic impacts we look at market clearing prices both overall and under non-scarcity conditions, and at total systems costs –accounting for changes in uplift payments to generators. Finally, a sensitivity analysis compares performance of the RCMC and StdMC for varying assumptions about URC/DRC prices, Over- and Under-generation penalties, and spinning reserve scarcity pricing.

4. Results

4.1. Procurement of RC

The RCMC algorithm does not necessarily alter the dispatch to procure URC and DRC in every interval. If there is no RC requirement or if the system state is sufficiently flexible in one direction, no RC will be procured in that direction (Table 1, categories 1–2). On the other hand, if the cost of procurement is higher than the demand curve, none or only some of the required RC will be procured (Table 1, categories 3, 5).

For all months and wind scenarios, it is more common to target RC in the day-ahead than in the real-time. URC requirements are zero in 7–27% of real-time intervals but only in 0–26% of day-ahead intervals (Table 1, category 1). Similarly, DRC requirements are zero in 8–28% of real-time intervals but only in 4–27% of day-ahead intervals.

URC is deployed in 9–17% of real-time intervals depending on the month and wind scenario, and in 27% – 52% of the day-ahead intervals (Table 1, sum of categories 4 and 5). These are the only intervals in which the existence of the URC product has any impact on commitment or dispatch. In the real-time market, no URC is available below the $10/MWh price cap in 14–24% of intervals (Table 1, category 3), whereas in the day-ahead market at least some targeted URC is always available below the price cap except in the July LW scenario. This increased URC deployment in day-ahead relative to real-time is in part due to the difference in frequency that URC is targeted, as noted above, but it is also due to the fact that the day-ahead market can commit additional resources to meet the URC target, while the real-time market can only use resources previously committed. In intervals when RC affects the real-time dispatch, an average of 45–69 MW of URC and 97–156 MW of DRC is procured.

DRC is typically deployed less frequently than URC, indicating that there is less of a need for downward flexibility and/or the system is inherently more flexible in the downward direction. When DRC is deployed, it is primarily in HW scenarios, where it is procured in 0–33% of day-ahead intervals and 0–21% of real-time intervals.

4.2. Wind power curtailment

Wind curtailment is infrequent under StdMC and occurs only during the April and July HW scenarios. RCMC results in fewer instances and lower quantity of wind curtailment: 54% fewer real-time intervals with curtailment in April (22 MWh less) and 23% fewer intervals with curtailment in July (45 MWh less).

The lack of representation of transmission constraints in our models is a likely cause of their low levels of wind curtailment relative to MISO's reality, where curtailment occurs primarily in wind-rich, transmission-constrained regions [34,35].

Table 1
Ramp capability procurement. For each month and wind combination, Table 1 shows the frequency at which different categories of procurement occurred: (1) No RC was targeted; (2) RC constraint was non-binding; system was sufficiently flexible; target was met without changing dispatch; (3) Procurement was too expensive; none of targeted RC was procured; (4) RC constraint was binding; all targeted RC was procured; (5) RC constraint was binding; some targeted RC was procured, but the demand curve limited full quantity. Not all rows add to 100% due to rounding.

		URC procurement					DRC procurement				
		No URC procured			URC procured		No DRC procured			DRC procured	
		1	2	3	4	5	1	2	3	4	5
January LW	Day Ahead	11%	63%	0%	2%	25%	16%	84%	0%	0%	0%
	Real Time	16%	61%	14%	1%	8%	16%	84%	0%	0%	0%
January HW	Day Ahead	0%	53%	0%	5%	42%	4%	72%	0%	14%	10%
	Real Time	7%	55%	24%	3%	12%	8%	77%	0%	9%	5%
April LW	Day Ahead	15%	59%	0%	2%	25%	14%	86%	0%	0%	0%
	Real Time	20%	54%	16%	1%	9%	19%	81%	0%	0%	0%
April HW	Day Ahead	1%	60%	0%	3%	36%	3%	73%	0%	15%	9%
	Real Time	11%	49%	25%	3%	12%	12%	80%	0%	5%	3%
July LW	Day Ahead	26%	38%	3%	2%	31%	27%	62%	0%	7%	3%
	Real Time	27%	43%	18%	1%	12%	28%	66%	0%	3%	2%
July HW	Day Ahead	1%	46%	1%	3%	49%	12%	55%	0%	19%	14%
	Real Time	12%	50%	21%	2%	15%	16%	63%	0%	12%	9%

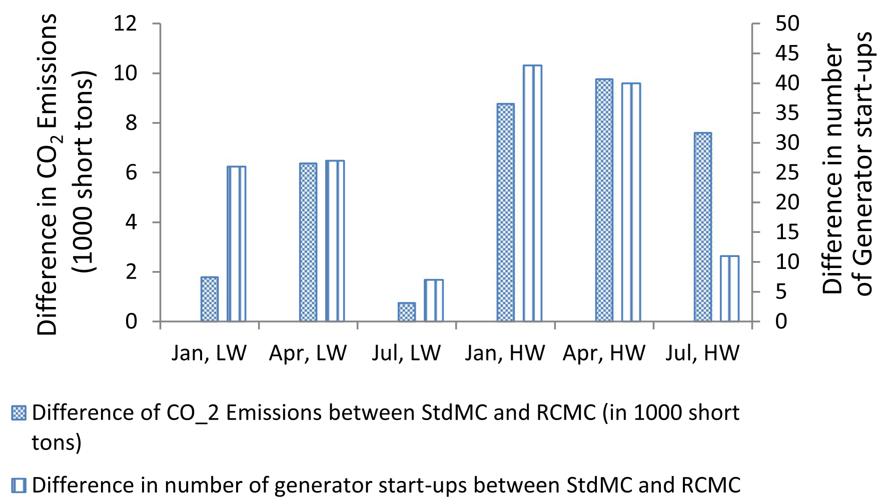

Fig. 2. Comparison of CO_2 emissions and number of generator start-ups. Emissions and startups in all month/wind combinations are reduced with the RCMC model.

4.3. Generation fuel mix and CO_2 emissions

RCMC reduces coal-fired generation by 0.03–0.18% for HW scenarios and 0–0.001% for LW scenarios, and reduces generator start-ups by 1.12–7.85% for HW and by 1.99–13.98% for LW. (Fig. 2). Since more fuel is used (and thus more CO_2 is emitted) during unit startups, a reduced number of generator start-ups together with fuel switching and lower wind curtailment should cause a reduction of CO_2 emissions under RCMC. This expectation holds true for all the months under both wind penetration scenarios. RCMC causes a reduction of 0.06–0.08% of CO_2 emissions under HW and 0.004–0.05% under LW. These figures may appear small, but are significant when considering that total MISO CO_2 emission in 2009 were approximately 1.14 billion tons [21]. Further, it is worth noting that the potential for these reductions is not entirely realized as no URC is procured in 14–25% of real time intervals (both LW and HW) due to its price cap being too low. As shown in section 4.6., increasing the value of economic benefit assigned to ramp capability further reduces emissions.

4.4. Reliability

We find that the RC products significantly improve system reliability, particularly as wind penetration increases. The occurrence of energy and spinning reserve shortages in the real-time is reduced for RCMC in all month and wind scenarios. In the HW scenario, which has a higher frequency of shortages compared to the LW scenario, the reductions shown in the RCMC model are also greater. Using StdMC, 4–13% of intervals contain energy shortages in the HW scenario depending on the month, while 28–30% of intervals contain spinning reserve shortages; in RCMC, these numbers fall to 3–12% and 26–28% respectively (Fig. 3). This indicates that the importance of RC products to help maintain reliability increases as wind penetration grows.

We note that the shortages of energy and reserve occurrences obtained in the simulation are much higher than in reality. In 2010, for example, MISO experienced spinning reserve shortages in just over 1% of all real-time intervals [34] and likely did not have any actual energy shortages. This difference is due to tools that ISOs have to deal with potential shortage events that are outside of the scope of our model, such as a short-term UC run, the ability to curtail load via demand response, and the manual dispatch (bypassing the outcome of the optimization models) of very expensive fast-ramping generators. Hence our shortage results should be seen in terms of the relative reduction from the baseline, which indicates a clear benefit from including RC products.

4.5. Market clearing prices and system costs

In order to assess the economic impacts of ramp capability products we compare real-time market clearing prices and system costs (including uplift payments). Procurement of URC and DRC products causes a slight increase of $0.85 - $1.95/MWh in the real-time prices under normal (non-shortage) conditions but this is more than offset by a reduction in price spikes, leading to overall average real-time energy market clearing prices that are 5–11% lower ($13/MWh–$67/MWh) than under the StdMC (Fig. 4). Average real time energy prices range from $250-$700/MWh, about ten times those observed in MISO's market in 2010 [34] as a consequence of the high frequencies of energy and spinning reserve shortages in the simulation described in section 3, which are associated with penalty prices of $3500/MWh and $1100/MWh respectively. Average prices under non-shortage conditions are much closer to MISO's actual average prices.

We calculate system costs for each month under StdMC and RCMC as summarized in table S19 of section 11 in the SI by estimating generators' revenue which is equal to the market revenue –from energy, reserve, and RC sales- plus Revenue Sufficiency Guarantee (RSG) or uplift payments which compensate generators when market revenue is insufficient to cover both fixed and marginal costs. RSG payments are calculated daily and equal the difference in market revenue received and costs incurred – consisting of fuel, no-load, and startup costs- by each generation unit. While RSG payments are important to generators' cost recovery, they tend to be far less transparent to market participants; all else equal, it is preferable for cost recovery to occur via market payments. Depending on the month and wind scenario, RSG payments are 3–18% lower and total system costs are 2–10% lower when RC products are included (Fig. 5).

4.6. Sensitivity analysis

We perform additional market clearing simulations to assess the effect of changes in the price caps assigned to URC and DRC, under and over generation penalties, and reserve scarcity pricing for the HW scenario. Table 2 shows the changes in the parameters for the sensitivity cases.

We first consider the performance of RCMC relative to StdMC with the same assumptions. As discussed above, under base case assumptions, RCMC results in reduced emissions, shortage intervals, prices, and costs relative to StdMC (Table 2, sensitivity case 0). If the URC/DRC price caps are augmented to $15/MWh, the improvement from RCMC is magnified for all performance metrics and all months (sensitivity case 1). For sensitivity case 2, when URC/DRC price caps are reduced to $5/MWh, the differences between StdMC and RCMC metrics are still in favor of RCMC but the improvements are nearly always lower than under the base-case assumptions.

In sensitivity cases 3–5, in which overgeneration, undergeneration, and reserve scarcity penalties are set at higher levels than in the base case, the advantage of RCMC over StdMC is preserved for all performance metrics. However, aside from overall MCP, in which improvements of RCMC are enhanced, there is not a clear trend of improvement relative to the base case for other metrics (see SI section 11) (Table 3).

This leads us to two observations about the attributes of the RCMC model: a) the superior environmental, cost and reliability performance of RCMC relative to StdMC holds and is sometimes enhanced under a

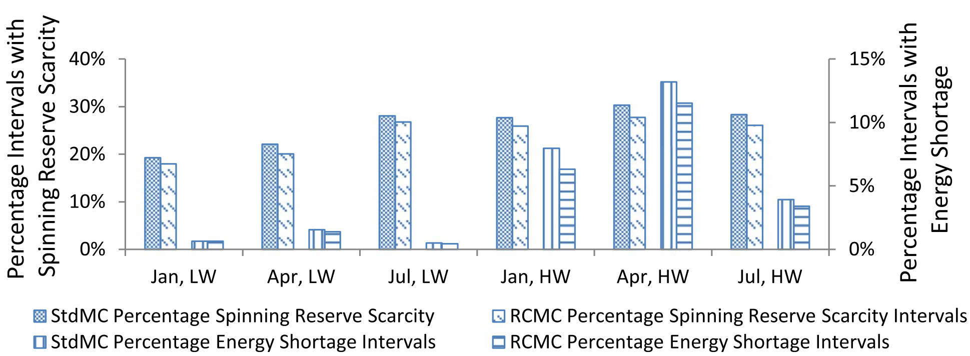

Fig. 3. Percent of intervals in real-time economic dispatch with spinning reserve scarcity and energy shortages. Shortages in all month/wind combinations are reduced with the RCMC model.

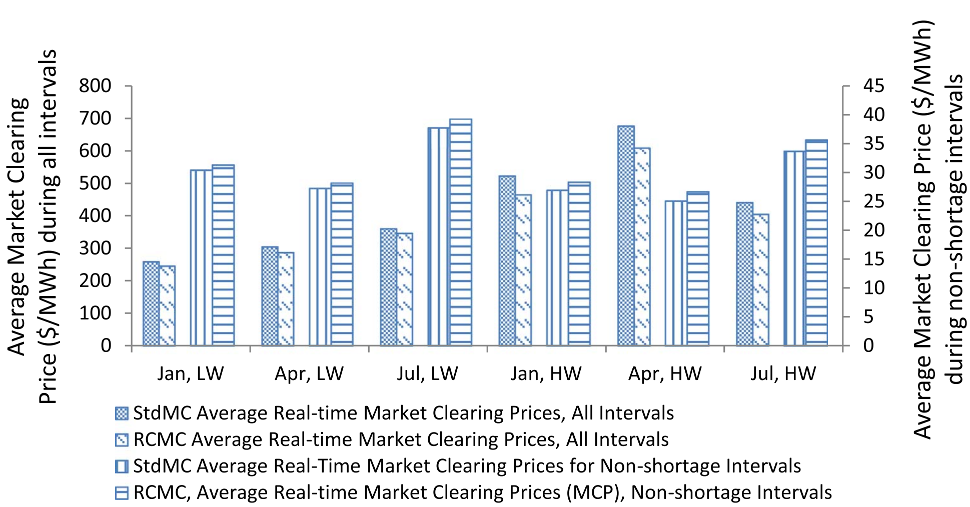

Fig. 4. Average real time market-clearing prices overall and in non-shortage intervals. The RCMC algorithm tends to have slightly higher prices in non-shortage intervals, but much lower prices overall, as shortages (and the associated high prices) are reduced relative to the StdMC algorithm.

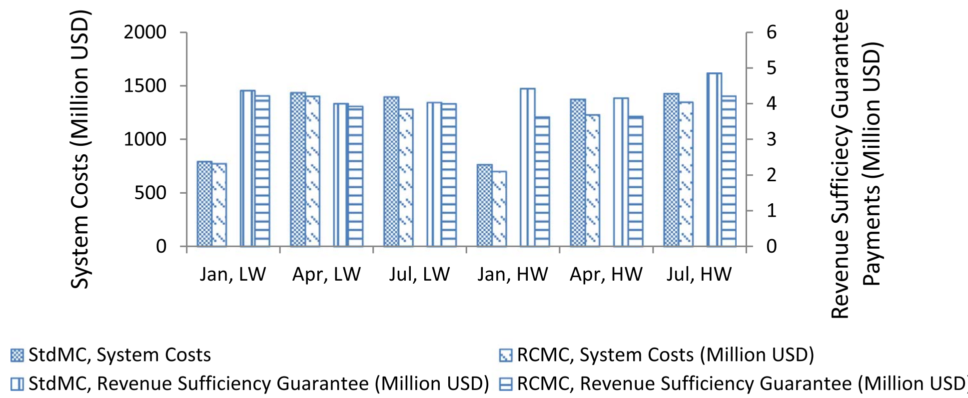

Fig. 5. Uplift costs and system costs. Both are lower with the RCMC algorithm in all month and wind scenarios.

Table 2
Description of sensitivity cases. Sensitivity cases modify model parameters described in the SI Section 7. RCUpDCPrice and RCDownDCPrice are the URC/DRC price caps, OverGenPen and UnderGenPen are the over and under generation penalties, SRScaricityPen is the spinning reserves scarcity penalty.

Sensitivity case	RCUpDCPrice ($/MWh)	RCDownDCPrice ($/MWh)	OverGenPen ($/MWh)	UnderGenPen ($/MWh)	SRScarcityPen ($/MWh)
0. Base Case Assumptions	10	10	500	3500	1100
1. Higher RCUpDCPrice, RCDownDCPrice	**15**	**15**	500	3500	1100
2. Lower RCUpDCPrice, RCDownDCPrice	**5**	**5**	500	3500	1100
3. Higher OverGenPen	10	10	**750**	3500	1100
4. Higher UnderGenPen	10	10	500	**5250**	1100
5. Higher SRScarcityPen	10	10	500	3500	**1650**

Table 3
Relative changes in costs, market clearing prices, emissions, start-ups and number of reserve scarcity events.

Results are differences between standard and flexiramp models with same assumptions (StdMC - FlexRMC) for high wind scenarios

Case	System Costs (Million USD)			Revenue Sufficiency Guarantee Payments (Million USD)			Average Market Clearing Price ($/MWh)			CO_2 Emissions (in 1000 Short tons)			No. of Generator Start-ups			Number of instances of Reserve Scarcity		
	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul
Base	61.1	98.7	176.1	0.6	0.5	0.5	57.8	64.5	36.0	8.8	9.8	7.6	43	40	11	78	110	100
1	125.5	156.6	316.5	0.7	0.6	0.5	61.7	77.5	66.5	11.3	10.2	9.6	63	60	21	128	124	186
2	11.7	74.4	60.0	0.4	0.3	0.5	11.9	5.4	13.8	3.2	9.3	4.6	22	30	11	6	22	45
3	61.5	237.1	169.2	0.5	0.3	0.6	71.2	71.6	43.5	8.1	55.1	6.7	48	39	17	114	53	126
4	83.2	93.5	218.7	0.7	0.5	0.6	110.6	76.0	42.8	8.4	54.4	6.7	46	34	9	127	50	95
5	67.1	107.3	222.9	0.7	0.3	0.6	84.7	79.5	41.2	14.2	49.6	9.0	35	33	12	179	113	255

Legend	
Improvement due to Ramp Capability Pricing	
Improvement more than base case	Improvement less than the base case

range of RC, shortage, surplus, and scarcity pricing parameters, and b) within the range of 5–15 $/MWh, the advantages of RCMC over StdMC appear to be positively correlated with URC/DRC price caps.

5. Discussion

Within our scaled-down representation of MISO's power system, we find that the introduction of RC products accomplishes the objective of facilitating wind integration while reducing system costs. Further, these benefits occur hand-in-hand with an improvement in reliability via reductions in the magnitude and frequency of intervals with energy or reserve shortages. While these shortages in the test system occur much more frequently than in MISO due to several model simplifications, they also serve as a proxy for intervals in which operators, in order to maintain reliability, would resort to actions that are outside of the scope of our model. Fewer shortage intervals indicate that there should be less need to commit expensive combustion turbine generators -currently used to meet short-term ramping needs- or to manually modify the dispatch –which compromises price transparency and consistency. Moreover, a transparently priced demand for RC may increase the incentives for generators to invest in faster-ramping generation.

While a simulation of a more realistic test system that includes bid-based market clearing, all ancillary services, transmission constraints, and short-term UC would be beneficial [3,7], our simplified model allows us to assess the overall performance of RCMC and to conduct parametric analysis of shortage penalty prices and RC price caps to determine ways in which these parameters can be tuned to enhance system performance with the use of RC products.

6. Conclusion

Our exploration of the benefits from increased URC/DRC price caps suggests that the performance of these products is highly sensitive to this parameter and likely, very system dependent. Nevertheless, our results show a clear improvement in environmental performance and confirm MISO's anticipated reliability and economic benefits of the RC products under a range of system conditions and pricing parameters.

Funding sources

This work received financial support from the Center for Climate and Energy Decision Making (SES-0949710) funded by the National Science Foundation, and from Duke University Energy Initiative and Bass Connections.

Acknowledgments

The authors thank V. Kumar for his assistance, and the members of the Bass Connections in Energy-MOTESA team for their support and feedback.

Appendix A. Supplementary material

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.rser.2017.06.037.

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