Assessing Environmental, Economic, and Reliability Impacts of Flexible Ramp Products in Midcontinent ISO

Adam Cornelius, Rubenka Bandyopadhyay, *Student Member, IEEE,* and Dalia Patiño-Echeverri, *Member*, *IEEE*

***Abstract*--Higher penetration of variable energy resources such as solar and wind increases the variability and uncertainty of net electrical load thereby augmenting the need for dispatching resources with sufficient ramping capability (RC). The Midcontinent Independent System Operator (MISO) intends to modify its Unit Commitment and Economic Dispatch algorithms to directly account for the economic value of provisioning an adequate level of RC. In this context, two new "products" arise: up ramp capability (URC) and down ramp capability (DRC).**

This paper explores the economic, reliability, and environmental outcomes of including URC and DRC in the market-clearing process by simulating 10-minute operations of a test system with an energy mix similar to MISO, for three representative months, and two scenarios with low and high wind penetration. Changes in system performance are quantified by comparing total system costs, scarcity events and pricing, energy prices, generation fuel mix, wind-power curtailment, and CO_2 emissions between the conventional market-clearing algorithm and the one with flexible ramp capability products. Results indicate that adding flexible-RC products facilitate wind energy integration while reducing system costs and improving reliability metrics; and that these improvements are robust to increases in over/under generation penalties and reserve scarcity pricing.

***Index Terms*—Optimization, Power generation dispatch, Power system economics, Power system reliability, Wind energy integration, Wind power generation**

I. Introduction

HIGHER penetration of Variable Energy Resources (VER) such as solar and wind increases the variability and uncertainty of net electrical load and therefore 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.

Independent System Operators (ISOs) in the U.S. have explored alternate scheduling processes to ensure the provision of enough RC, including the implementation of look-ahead Unit Commitment (UC) and Economic Dispatch (ED) algorithms, and the creation of RC products. For example, the Midcontinent Independent System Operator (MISO) - serving 42 million people and containing over 175GW of total generation capacity, including 13GW of wind [1] – has recently implemented a look-ahead UC algorithm close to real time that optimizes over the next several intervals. However, the current real-time ED algorithm does not look ahead to ensure that potential future ramping needs are met [2], and as a consequence the system may not have access to sufficient RC in some real-time intervals. When shortages of RC are forecasted, MISO's operators make out-of-market adjustments to the optimal schedules suggested by the UC and ED algorithms.

While these adjustments are necessary from a reliability standpoint they 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, the intermittency of renewables is a big contributor. As renewable penetration increases the issue will only be exacerbated further [3].

In 2016, MISO plans to implement 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. Generators will not separately offer RC; instead by submitting an offer to provide energy in the day-ahead, 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].

MISO's plan is presented in two pieces by Navid and

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A. Cornelius was an MEM student at the Nicholas School of the Environment at Duke University, Durham, NC 27705, USA. He is now with the Federal Energy Regulatory Commission (FERC), Washington, DC 20426, USA (e-mail: adam.cornelius@gmail.com). His substantive work on this research was performed at Duke University prior to his employment at FERC. The opinions expressed in this paper are those of the authors only, and do not represent the views of the US Government, FERC, nor of any Commissioners.

R. Bandyopadhyay is a PhD student at the Nicholas School of the Environment at Duke University Durham, NC 27705, USA (e-mail: rb171@duke.edu).

D. Patiño-Echeverri is an assistant professor at the Nicholas School of the Environment at Duke University Durham, NC 27705, USA (e-mail: dalia.patino@duke.edu).

Rosenwald [3]-[4], in a cost-benefit analysis by Navid et al. [5], and in a proposal that has been conditionally approved by the Federal Energy Regulatory Commission [6]. A similar proposal for the California Independent System Operator (CAISO) is presented by Xu and Tretheway [7] while Wang and Hobbs [8] 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. Most of these analyses of potential benefits of RC products are based on small test systems containing at most five generating units [4], [7]-[8], with the exception of [3], [5] which analyze the entire MISO system for 4 sample days from which annual impacts are extrapolated.

In general these studies indicate that the proposed RC products would result in net savings. Although small increases in 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 [7]-[8]. 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 resulting from transmission constraint violations [3]-[5].

The 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 [7]

II. Objectives

The purpose of this work is to further explore the economic, environmental, and reliability costs and benefits of RC products in an analysis that differs from previous studies in: a) the detail of representation of MISO's power generation fleet, b) the length and time-resolution of the period of analysis, c) the consideration of environmental benefits, 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 ramp-capability products under different design parameters, system penalties for under/over generation, and scarcity pricing.

Our model has 44 coal and gas generators whose operation is simulated during 3 representative months, according to hourly day-ahead UC and ED algorithms and a 10-minute real-time ED algorithm, using real load data from MISO and wind data from the National Renewable Energy Laboratory's (NREL's) Eastern Wind Integration and Transmission Survey (EWITS). Because EWITS data is only available in 10-minute intervals, this is the granularity used for real-time model runs. We estimate changes in total system costs (including the costs of reserves and payments for flexi-ramp), scarcity events and pricing, overall energy prices, generation fuel mix, wind-power curtailment, and CO_2 emissions, between the standard market clearing process (StdMC) and a market clearing process that includes ramp capability products (RCMC).

III. Data and Methods

A. Data

We set up a representative system that has 6% of MISO's load and generation capacity with roughly the same proportion of coal, natural gas, and nuclear power as MISO in 2009 [9]. The low-wind penetration system has wind nameplate capacity equal to 7% of total generation capacity (the same proportion as in 2009); the high wind penetration system 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. Significant detail on the test system used and other assumptions and methods can be found at [10].

A k-means clustering analysis is used to select 44 coal and natural gas generators from MISO's fleet [10]. Cost and performance data are taken from various sources. Name plate capacity, average heat rates and CO2 emissions are taken from eGRID [9] and EIA Form 923 [11]. Required minimum generation levels and maximum ramp-rates for each power generator are set according to a study from the Northwest Power and Conservation Council [12], minimum up and down times are from [13], and no-load costs are set based on generator type and size from a Lawrence Berkeley National Laboratory study [14]. Start-up costs are set equal to the median of values for like generator types as reported in NRELs Power Plant Cycling Costs study [15].

We use EIA-reported average prices of coal and natural gas for electric power from the five-year period ending in March 2014 [16] 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 low and high wind systems correspond to modeled wind sites in the MISO states selected from EWITS [17]. Day-ahead hourly forecasts of wind generation required to simulate the day-ahead market are set equal to the forecasts provided by EWITS. 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% (consistent with the 3% standard deviation for 5-minute ahead wind forecast in MISO [3]).

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 [18], [10]. 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-minute intervals. MISO reports forecast error standard deviations of 1% in the day ahead and 0.12% for 5-minute forecasts [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 [10].

Other parameters necessary for the StdMC and RCMC models are taken from MISO documents; spinning reserves

TABLE I
NOTATION USED IN MODEL FORMULATIONS

Indices	
u	Index for dispatchable unit, $u \in 1..U$
t	Index for time interval, $t \in 1..T$
n	Intermediate time interval index used for minimum up and downtime requirements, $n \in t..$
System Requirement Parameters	
IntLength	Length of each time interval [minutes]
$\mathrm{FDemand}_t$	Forecasted system demand in interval t [MW]
$\mathrm{ActDemand}_t$	Actual system demand in interval t [MW]
$\mathrm{VForecast}_t$	Forecasted wind power in interval t [MW]
$\mathrm{VAvailable}_t$	Actual available wind power in interval t [MW]
$\mathrm{SpinReq}_t$	Quantity of spinning reserve required in interval t [MW]
ResResponseTime	Time by which reserve from generator u must be deployable [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]
RampResponseTime	Response time for ramp capability (used in day-ahead models) [minutes]
RampInts	Number of intervals for which ramp capability is considered (used in real-time model) [intervals]
System Penalty and Price Parameters	
OverGenPen	System-wide over generation penalty [$/MWh]
UnderGenPen	System-wide under generation penalty [$/MWh]
SRScarcityPen	System-wide spinning reserve shortage penalty [$/MWh]
RCUpDCPrice*	URC Demand Curve Price [$/MWh]
RCDownDCPrice*	DRC Demand Curve Price [$/MWh]
MCPE_t *	Market Clearing Price for Energy Market at time t
MCPSR_t*	Market Clearing Price for Spinning Reserves at time t
Generator Cost Parameters	
MC_u	Marginal Cost of operating dispatchable unit u [$/MW/interval]
SRC_u	Cost of spinning reserve provided by unit u [$/MW/interval]
NLC_u*	No load cost (fixed operation cost) of operating unit u [$/interval]
StartC_u*	Cost of starting unit u [$]
Generator Operating Parameters	
$\mathrm{Commit}_{u,t}$	Commitment status of unit u in interval t (only a parameter in economic dispatch models)
MaxGen_u	Maximum generation of unit u [MW]
MinGen_u	Minimum generation of unit u [MW]
$\mathrm{PosRampRate}_u$	Maximum ramp-up rate of generator u [MW/interval]
$\mathrm{NegRampRate}_u$	Maximum ramp-down rate of generator u [MW/interval]
MinUT_u	Minimum uptime of unit u [intervals]
MinDT_u	Minimum downtime of unit u [intervals]
$\mathrm{InitMinUp}_u$	Number of intervals generator u must be up at the start of the optimization period due to its initial uptime [intervals]
$\mathrm{InitMinDown}_u$	Number of intervals generator u must be down at the start of the optimization period due to its initial downtime [intervals]
FutureSDu	Number of intervals beyond the end of the RTED time horizon that unit u will shut down [intervals]
$\mathrm{SUIntsRemain}_{u,t}$	Number of intervals remaining until generator u should have fully started up and reached its minimum capacity level [intervals]
$\mathrm{ShuttingDown}_{u,t}$	Indicates whether the unit is shutting down and the minimum generation should be relaxed to 0 [binary]
Decision Variables	
$\mathrm{Gen}_{u,t}$*	Average power generation of unit u in interval t [MW]
$\mathrm{SR}_{u,t}$*	Spinning reserve provided by unit u in interval t [MW]
$\mathrm{Commit}_{u,t}^{\#}$*	Commitment status of unit u in interval t (only a decision variable in unit commitment models) [binary]
$\mathrm{StartCost}_{u,t}^{\#}$	Startup cost of unit u in interval t [$]
$\mathrm{OverGen}_t$	Surplus of generation over demand in interval t [MW]
$\mathrm{UnderGen}_t$	Shortage of generation below demand in interval t [MW]
$\mathrm{UnmetSR}_t$	Shortage of spinning reserve below requirement in interval t [MW]
$\mathrm{VSchedule}_{t,t}$	Quantity of variable generation scheduled in interval t [MW]
$\mathrm{UnitRCUp}_{u,t}$*	URC supplied by unit u in interval t [MW]
$\mathrm{UnitRCDown}_{u,t}$*	DRC supplied by unit u in interval t [MW]
RCUp_t	System URC procured in interval t [MW]
RCDown_t	System DRC procured in interval t [MW]
$\mathrm{Started}_{u,t}$*	Start-up status of unit u in interval t of a given day d [binary]

* Used for system cost calculations in Table VI
\# These decision variables are determined by the B-DAUC and RC-DAUC models

TABLE II
DAY AHEAD UNIT COMMITMENT MODELS

Day Ahead Unit Commitment Model for StdMC (DAUC)

$$\mathrm{Min}\ \sum_{t=1}^{T}\Big(\sum_{u=1}^{U}\big(\mathrm{Gen}_{u,t} * \mathrm{MC}_u + \mathrm{SR}_{u,t} \times \mathrm{SRC}_u + \mathrm{Commit}_{u,t} \times \mathrm{NLC}_u + \mathrm{StartCost}_{u,t}\big) + \mathrm{OverGen}_t \times \mathrm{OverGenPen} + \mathrm{UnderGen}_t \times \mathrm{UnderGenPen} + \mathrm{UnmetSR}_t \times \mathrm{SRScarcityPen}\Big) \quad (1)$$

Subject to:

$$\sum_{u=1}^{U}\mathrm{Gen}_{u,t} + \mathrm{VSchedule}_t + \mathrm{UnderGen}_t - \mathrm{OverGen}_t = \mathrm{FDemand}_t \quad \forall\, t \quad (2)$$

$$\sum_{u=1}^{U}\mathrm{SR}_{u,t} + \mathrm{UnmetSR}_t \geq \mathrm{SpinReq}_t \quad \forall\, t \quad (3)$$

$$\mathrm{VSchedule}_t \leq \mathrm{VForecast}_t \ \ \forall\, t \quad (4)$$

$$\mathrm{StartCost}_{u,t} \geq \mathrm{StartC}_u \times \big(\mathrm{Commit}_{u,t} - \mathrm{Commit}_{u,t-1}\big) \quad \forall\, u,t \quad (5)$$

$$\mathrm{Gen}_{u,t} + \mathrm{SR}_{u,t} \leq \mathrm{MaxGen}_u \times \mathrm{Commit}_{u,t} \ \ \forall\, u,t \quad (6)$$

$$\mathrm{Gen}_{u,t} \geq \mathrm{MinGen}_u \times \mathrm{Commit}_{u,t} \ \ \forall\, u,t \quad (7)$$

$$\mathrm{Gen}_{u,t} - \mathrm{Gen}_{u,t-1} \leq \mathrm{IntLength} \times \mathrm{PosRampRate}_u \ \ \forall\, u,t \quad (8)$$

$$\mathrm{Gen}_{u,t-1} - \mathrm{Gen}_{u,t} \leq \mathrm{IntLength} \times \mathrm{NegRampRate}_u \ \ \forall\, u,t \quad (9)$$

$$\mathrm{SRes}_{u,t}/\mathrm{ResResponseTime} \leq \mathrm{PosRampRate}_u \ \ \forall\, u,t \quad (10)$$

$$\sum_{t=1}^{\mathrm{InitMinUp}_u}\big(1 - \mathrm{Commit}_{u,t}\big) = 0 \quad \forall\, u \quad (11)$$

$$\sum_{n=t}^{t+\mathrm{MinUT}_u-1}\big(\mathrm{Commit}_{u,n}\big) \geq \mathrm{MinDT}_u \times \big(\mathrm{Commit}_{u,t} - \mathrm{Commit}_{u,t-1}\big) \ \ \forall\, u, \forall\, t \in \{\mathrm{InitMinUp}_u + 1, \mathrm{T} - \mathrm{MinUT}_u + 1\} \quad (12)$$

$$\sum_{n=t}^{T}\Big(\mathrm{Commit}_{u,n} - \big(\mathrm{Commit}_{u,t} - \mathrm{Commit}_{u,t-1}\big)\Big) \geq 0 \quad \forall\, u, \forall t \in \{\mathrm{T} - \mathrm{MinUT}_u + 2, \mathrm{T}\} \quad (13)$$

$$\sum_{t=1}^{\mathrm{InitMinDown}_u}\mathrm{Commit}_{u,t} = 0 \quad \forall\, u \quad (14)$$

$$\sum_{n=t}^{t+\mathrm{MinDT}_u-1}\big(1 - \mathrm{Commit}_{u,n}\big) \geq \mathrm{MinDT}_u \times \big(\mathrm{Commit}_{u,t-1} - \mathrm{Commit}_{u,t}\big) \ \ \forall\, u, \forall\, t \in \{\mathrm{InitMinDown}_u + 1, \mathrm{T} - \mathrm{MinDT}_u + 1\} \quad (15)$$

$$\sum_{n=t}^{T}\Big(\big(1 - \mathrm{Commit}_{u,n}\big) - \big(\mathrm{Commit}_{u,t-1} - \mathrm{Commit}_{u,t}\big)\Big) \geq 0 \quad \forall\, u, \forall t \in \{\mathrm{T} - \mathrm{MinDT}_u + 2, \mathrm{T}\} \quad (16)$$

$$\mathrm{Gen}_{u,t}, \mathrm{SR}_{u,t}, \mathrm{StartCost}_{u,t}, \mathrm{OverGen}_t, \mathrm{UnderGen}_t, \mathrm{UnmetSR}_t, \mathrm{VSchedule}_t \geq 0\ \forall u, t \quad (17)$$

Day Ahead Unit Commitment for RCMC (RC-DAUC)

Objective function is equal to (1) with the additional terms:

$$-\sum_{t=1}^{T}\big(\mathrm{RCUp}_t \times \mathrm{RCUpDCPrice} + \mathrm{RCDown}_t \times \mathrm{RCDownDCPrice}\big) \quad (18)$$

All constraints the same as (2)-(17) with the following modifications:

Change to constraint (6):

$$\mathrm{Gen}_{u,t} + \mathrm{SR}_{u,t} + \mathrm{UnitRCUp}_{u,t} \leq \mathrm{MaxGen}_u \times \mathrm{Commit}_{u,t} \ \ \forall\, u,t \quad (19)$$

Change to constraint (7):

$$\mathrm{Gen}_{u,t} - \mathrm{UnitRCDown}_{u,t} \geq \mathrm{MinGen}_u \times \mathrm{Commit}_{u,t} \ \ \forall\, u,t \quad (20)$$

Additional components for constraint (17):

$$\mathrm{UnitRCUp}_{u,t}, \mathrm{UnitRCDown}_{u,t}, \mathrm{RCUp}_t, \mathrm{RCDown}_t \geq 0\ \forall t \quad (21)$$

New Constraints:

$$\mathrm{UnitRCUp}_{u,t}/\mathrm{RampResponseTime} \leq \mathrm{PosRampRate}_u \ \ \forall\, u,t \quad (22)$$

$$\mathrm{UnitRCDown}_{u,t}/\mathrm{RampResponseTime} \leq \mathrm{NegRampRate}_u \quad \forall u,t \quad (23)$$

$$\mathrm{RCUp}_t \leq \mathrm{RCUpDCMax}_t \ \ \forall t \quad (24)$$

$$\mathrm{RCDown}_t \leq \mathrm{RCDownDCMax}_t \ \ \forall t \quad (25)$$

$$\sum_{u}^{\mathrm{Units}}\mathrm{UnitRCUp}_{u,t} \geq \mathrm{RCUp}_t \quad \forall t \quad (26)$$

$$\sum_{u}^{\mathrm{Units}}\mathrm{UnitRCDown}_{u,t} \geq \mathrm{RCDown}_t \quad \forall t \quad (27)$$

must be capable of being deployed within 10 minutes with a penalty of $1,100/MWh if there is a shortage; there is a penalty of $3,500/MWh for under-generation (VOLL) and $500/MWh for over-generation [19]; 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]. A sensitivity analysis varying these parameters is reported in Section IV-F.

B. Method

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 tables II-IV. The models assume a competitive market where all generators bid their marginal costs. A single iteration of the B-DAUC/B-DAED models uses day-ahead forecasts of load and wind generation to produce co-optimized hourly commitment, generation and reserve schedules, and market prices 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: RC-DAUC, RC-DAED, RC-RTED. The up and down capability requirements $\mathrm{RCUpDCMax}_t$ and $\mathrm{RCDownDCMax}_t$ that are inputs in the RC models are set in the real time as:

$$\mathrm{RCUpDCMax}_t = \max\big\{\mathrm{FNetLoad}_{t+1} - \mathrm{ActNetLoad}_t + \mathrm{Uncert}_{\mathrm{up}_{t+1}}, 0\big\}$$

TABLE III
DAY AHEAD ECONOMIC DISPATCH MODELS

Day Ahead Economic Dispatch Model for StdMC (B-DAED)	
Min $\sum_{t=1}^{T}\left(\sum_{u=1}^{U}\left(\mathrm{Gen}_{u,t}\times \mathrm{MC}_u + \mathrm{SR}_{u,t}\times \mathrm{SRC}_u\right) + \mathrm{OverGen}_t \times \mathrm{OverGenPen} + \mathrm{UnderGen}_t \times \mathrm{UnderGenPen} + \mathrm{UnmetSR}_t \times \mathrm{SRScarcityPen}\right)$	(28)
Subject to:	
$\sum_{u=1}^{U}\mathrm{Gen}_{u,t} + \mathrm{VSchedule}_t + \mathrm{UnderGen}_t - \mathrm{OverGen}_t = \mathrm{FDemand}_t \quad \forall\, t$	(29)
$\sum_{u=1}^{U}\mathrm{SR}_{u,t} + \mathrm{UnmetSR}_t \geq \mathrm{SpinReq}_t \quad \forall\, t$	(30)
$\mathrm{VSchedule}_t \leq \mathrm{VForecast}_t \;\; \forall\, t$	(31)
$\mathrm{Gen}_{u,t} + \mathrm{SR}_{u,t} \leq \mathrm{MaxGen}_u \times \mathrm{Commit}_{u,t} \;\; \forall\, u,t$	(32)
$\mathrm{Gen}_{u,t} \geq \mathrm{MinGen}_u \times \mathrm{Commit}_{u,t} \;\; \forall\, u,t$	(33)
$\mathrm{Gen}_{u,t} - \mathrm{Gen}_{u,t-1} \leq \mathrm{IntLength} \times \mathrm{PosRampRate}_u \;\; \forall\, u,t$	(34)
$\mathrm{Gen}_{u,t-1} - \mathrm{Gen}_{u,t} \leq \mathrm{IntLength} \times \mathrm{NegRampRate}_u \;\; \forall\, u,t$	(35)
$\frac{\mathrm{SR}_{u,t}}{\mathrm{ResResponseTime}} \leq \mathrm{PosRampRate}_u \;\; \forall\, u,t$	(36)
$\mathrm{Gen}_{u,t}, \mathrm{SR}_{u,t}, \mathrm{OverGen}_t, \mathrm{UnderGen}_t, \mathrm{UnmetSR}_t, \mathrm{VSchedule}_t \geq 0 \;\forall u,t$	(37)
Day Ahead Economic Dispatch Model for RCMC (RC-DAED)	
Objective function is equal to (28) with the additional terms:	
$-\sum_{t=1}^{T}(\mathrm{RCUp}_t \times \mathrm{RCUpDCPrice} + \mathrm{RCDown}_t \times \mathrm{RCDownDCPrice})$	(38)
All constraints the same as (29)-(37) with the following modifications:	
Change to constraint (32):	
$\mathrm{Gen}_{u,t} + \mathrm{SR}_{u,t} + \mathrm{UnitRCUp}_{u,t} \leq \mathrm{MaxGen}_u \times \mathrm{Commit}_{u,t} \;\; \forall\, u,t$	(39)
Change to constraint (33):	
$\mathrm{Gen}_{u,t} - \mathrm{UnitRCDown}_{u,t} \geq \mathrm{MinGen}_u \times \mathrm{Commit}_{u,t} \;\; \forall\, u,t$	(40)
Additional components for constraint (37):	
$\mathrm{UnitRCUp}_{u,t}, \mathrm{UnitRCDown}_{u,t}, \mathrm{RCUp}_t, \mathrm{RCDown}_t \geq 0 \;\forall t$	(41)
New Constraints:	
$\mathrm{UnitRCUp}_{u,t}/\mathrm{RampResponseTime} \leq \mathrm{PosRampRate}_u \;\; \forall\, u,t$	(42)
$\mathrm{UnitRCDown}_{u,t}/\mathrm{RampResponseTime} \leq \mathrm{NegRampRate}_u \;\; \forall u,t$	(43)
$\mathrm{RCUp}_t \leq \mathrm{RCUpDCMax}_t \;\; \forall t$	(44)
$\mathrm{RCDown}_t \leq \mathrm{RCDownDCMax}_t \;\; \forall t$	(45)
$\sum_{u}^{\mathrm{Units}}\mathrm{UnitRCUp}_{u,t} \geq \mathrm{RCUp}_t \quad \forall t$	(46)
$\sum_{u}^{\mathrm{Units}}\mathrm{UnitRCDown}_{u,t} \geq \mathrm{RCDown}_t \quad \forall t$	(47)

TABLE IV
REAL TIME ECONOMIC DISPATCH MODELS

Real Time Economic Dispatch Model for StdMC (B-RTED)	
The objective function is the same as that in B-DAED	
All constraints the same as (29)-(37) with the following modifications:	
Constraint (29) is replaced with:	
$\sum_{u=1}^{U}\mathrm{Gen}_{u,t} + \mathrm{VSchedule}_t + \mathrm{UnderGen}_t - \mathrm{OverGen}_t = \mathrm{ActDemand}_t \quad \forall\, t$	(48)
Constraint (31) is replaced with:	
$\mathrm{VSchedule}_t \leq \mathrm{VAvailable}_t \;\; \forall\, t$	(49)
Constraint 33 is replaced with:	
$\mathrm{Gen}_{u,t} \geq \left(\mathrm{MinGen}_u \times \mathrm{Commit}_{u,t} - \mathrm{SUIntsRemain}_{u,t} * \mathrm{PosRampRate}_u * \mathrm{IntLength}\right) * (1 - \mathrm{ShuttingDown}_{u,t}) \;\forall\, u,t$	(50)
New Constraint	
$\mathrm{Gen}_{u,t} \leq (\mathrm{FutureSD}_u + \mathrm{T} - \mathrm{t}) \times \mathrm{IntLength} \times \mathrm{NegRampRate}_u \;\; \forall\, u,$	(51)
Real Time Economic Dispatch for RCMC (RC-RTED)	
The objective function is the same as that in RC-DAED	
All constraints the same as 39-47 with the following modifications:	
Constraint (39) is replaced with:	
$\sum_{u=1}^{U}\mathrm{Gen}_{u,t} + \mathrm{VSchedule}_t + \mathrm{UnderGen}_t - \mathrm{OverGen}_t = \mathrm{ActDemand}_t \quad \forall\, t$	(52)
Constraint (31) is replaced with:	
$\mathrm{VSchedule}_t \leq \mathrm{VAvailable}_t \;\; \forall\, t$	(53)
Constraint (40) is replaced with:	
$\mathrm{Gen}_{u,t} \geq \left(\mathrm{MinGen}_u \times \mathrm{Commit}_{u,t} - \mathrm{SUIntsRemain}_{u,t} * \mathrm{PosRampRate}_u * \mathrm{IntLength}\right) * (1 - \mathrm{ShuttingDown}_{u,t}) \;\forall\, u,t$	(54)
Change to constraint (42):	
$\frac{\mathrm{UnitRCUp}_{u,t}}{\mathrm{RampInts}*\mathrm{IntLength}} \leq \mathrm{PosRampRate}_u \;\; \forall\, u,t$	(55)
Change to constraint 43	
$\frac{\mathrm{UnitRCDown}_{u,t}}{\mathrm{RampInts}*\mathrm{Intlength}} \leq \mathrm{NegRampRate}_u \quad \forall u,t$	(56)
New Constraints:	
$\mathrm{Gen}_{u,t} + \mathrm{UnitRCUp}_{u,t} \leq (\mathrm{FutureSD}_u + \mathrm{T} - \mathrm{t}) \times \mathrm{IntLength} \times \mathrm{NegRampRate}_u \;\; \forall\, u,t$	(57)

$$\mathrm{RCDownDCMax}_t = \max\left\{\mathrm{ActNetLoad}_t - \mathrm{FNetLoad}_{t+1+}\mathrm{Uncert}_{\mathrm{down}_{t+1}}, 0\right\}$$

And in the day-ahead as:

$$\mathrm{RCUpDCMax}_t = \max\left\{(\mathrm{FNetLoad}_{t+1} - \mathrm{FNetLoad}_t)\ \mathrm{x}\,\frac{\mathrm{RampResponseTime}}{\mathrm{IntLength}} + \mathrm{Uncert}_{\mathrm{up}_{t+1}}, 0\right\}$$

$$\mathrm{RCDownDCMax}_t = \max\left\{(\mathrm{FNetLoad}_t - \mathrm{FNetLoad}_{t+1})\ \mathrm{x}\,\frac{\mathrm{RampResponseTime}}{\mathrm{IntLength}} + \mathrm{Uncert}_{down_{t+1}}, 0\right\}$$

Where:

$$\mathrm{FNetLoad}_t = \mathrm{FDemand}_t - \mathrm{VForecast}_t$$
$$\mathrm{ActNetLoad}_t = \mathrm{ActDemand}_t - \mathrm{VAvailable}_t$$
$$\mathrm{RampResponseTime} = 10 \text{ minutes}$$
$$\text{Day ahead IntLength} = 60 \text{ minutes}$$

The difference in the real-time and day-ahead formulations 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 interval. The day-ahead model, on the other hand, procures RC to ensure that there is sufficient intra-interval flexibility 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 estimates of $\mathrm{Uncert}_{\mathrm{up}_{t+1}}$ and $\mathrm{Uncert}_{\mathrm{down}_{t+1}}$ depend on the time-regime T to which the time interval belongs. We partition the historical time series of $\mathrm{ActNetLoad}_t$ 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:

$$\mathrm{Uncert}_{\mathrm{up}_{t+1}} = \mathrm{UncUpPct}_T \times \mathrm{FNetLoad}_{t+1}$$
$$\mathrm{Uncert}_{\mathrm{down}_{t+1}} = \mathrm{UncDownPct}_T \times \mathrm{FNetLoad}_{t+1}$$
$$\mathrm{UncUpPct}_T = \mathrm{AvgRampPct}_T + 2 \times \mathrm{SDRampPct}_T$$
$$\mathrm{UncDownPct}_T = \mathrm{AvgRampPct}_T - 2 \times \mathrm{SDRampPct}_T$$

Where $\mathrm{AvgRampPct}_T$ and $\mathrm{SDRampPct}_T$ are the average and standard deviation of a time series of $\mathrm{RampPct}_t$ values estimated from a historical times-series of $\mathrm{ActNetLoad}_t$ as:

$$\mathrm{RampPct}_t = (\mathrm{ActNetLoad}_{t+1} - \mathrm{ActNetLoad}_t)/\mathrm{ActNetLoad}_t$$

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 [10].

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.

To assess environmental impacts of the introduction of RC products, we look at changes in CO_2 operational emissions, number of power generator start-ups, and wind curtailment by directly comparing simulation results for the RCMC and StdMC models. To examine economic impacts we look at market clearing prices overall, and under non-scarcity conditions, and at total systems costs –accounting for changes in uplift payments to generators. Finally for an assessment of reliability outcomes we look at the occurrences and amounts of energy and reserve shortages.

IV. Results

A. 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 V, 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 V, categories 3, 5).

TABLE V
Ramp Capability Procurement

		URC Procurement				
		No URC Procured			URC Procured	
		(1)	(2)	(3)	(4)	(5)
January Low Wind	Day Ahead	6%	43%	0%	21%	29%
	Real Time	22%	37%	4%	9%	28%
January High Wind	Day Ahead	7%	38%	0%	29%	25%
	Real Time	14%	34%	8%	14%	31%
April Low Wind	Day Ahead	1%	31%	0%	39%	29%
	Real Time	18%	33%	4%	16%	28%
April High Wind	Day Ahead	1%	30%	0%	43%	26%
	Real Time	11%	27%	9%	19%	34%
July Low Wind	Day Ahead	0%	24%	3%	18%	55%
	Real Time	21%	29%	8%	7%	36%
July High Wind	Day Ahead	0%	24%	0%	20%	56%
	Real Time	8%	30%	10%	10%	42%
		DRC Procurement				
		No DRC Procured			DRC Procured	
		(1)	(2)	(3)	(4)	(5)
January Low Wind	Day Ahead	5%	95%	0%	0%	0%
	Real Time	13%	87%	0%	0%	0%
January High Wind	Day Ahead	7%	93%	0%	0%	0%
	Real Time	12%	85%	0%	2%	1%
April Low Wind	Day Ahead	7%	93%	0%	1%	0%
	Real Time	14%	86%	0%	0%	0%
April High Wind	Day Ahead	8%	81%	0%	8%	3%
	Real Time	12%	75%	0%	6%	7%
July Low Wind	Day Ahead	9%	79%	0%	9%	3%
	Real Time	25%	74%	0%	0%	0%
July High Wind	Day Ahead	12%	69%	0%	12%	8%
	Real Time	12%	71%	0%	9%	8%

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

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 8%-22% of real-time intervals but only in 0%-7% of day-ahead intervals (Table V, category 1). Similarly, DRC requirements are zero in 12%-25% of real-time intervals but only in 5%-12% of day-ahead intervals.

URC is deployed in 50%-76% of the day-ahead intervals depending on the month and wind scenario, and in 36%-53% of intervals in the real-time (Table V, 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 4-10% of intervals (Table V, category 3), whereas in the day ahead market at least some targeted URC is always available below the price cap except in the July low wind 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 50-75 MW of URC and 133-201 MW of DRC is procured.

DRC is deployed far less frequently than URC, and primarily in high wind scenarios, where it is procured in 0-19% of day-ahead intervals and 3-17% of real-time intervals. This indicates that there is less of a need for downward flexibility and/or the system is generally more flexible in the downward direction.

B. 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 in general reduced for the RCMC model.

In the StdMC model 1-9% of intervals contain energy shortages depending on the month and wind scenario while 24-38% of intervals contain spinning reserve shortages (Fig. 1). In each month, there are more energy shortages and the

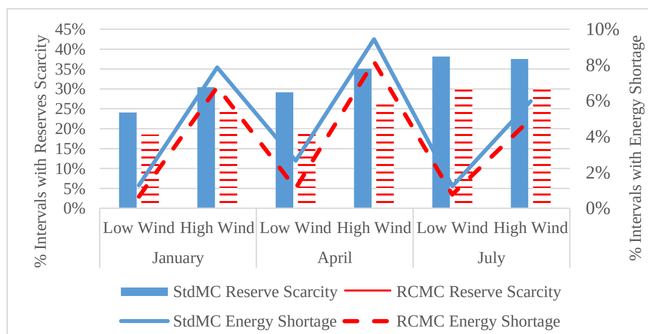

Fig. 1. Percent of intervals in real-time economic dispatch with spinning reserve scarcity and energy shortages. Shortages in all month/wind combinations are reduced with the RCMC model.

same or more reserve shortages under the high wind scenario (with the exception of July, when reserve shortages are 0.6% lower under high wind). The URC and DRC products cause a reduction in both types of shortages in all month/wind scenario combinations. 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 [20] 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.

C. 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 \$1.6 - \$2.7/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 15% to 35% lower (\$74/MWh-\$140/MWh) than under the StdMC (Fig. 2). Average real time energy prices range from \$300-\$600/MWh, about ten times those observed in MISO's market in 2010 [20] as a consequence of the high frequencies of energy and spinning reserve shortages in the simulation described in section B, which are associated with penalty prices of \$3,500/MWh and \$1,100/MWh respectively. Average prices under non-shortage conditions are much closer to MISO's actual average prices.

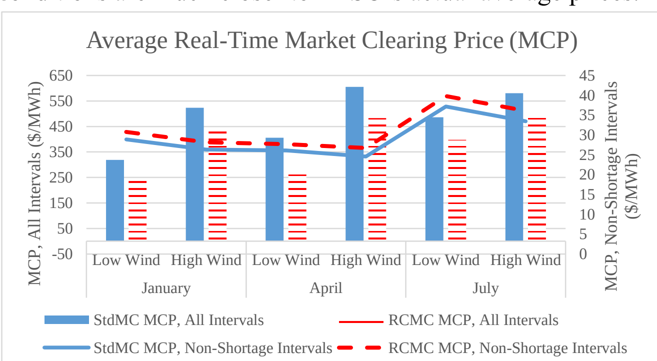

Fig. 2. Average real time market-clearing prices overall and in non-shortage intervals. The RCMC algorithm tends to have slightly higher prices in non-shortage intervals, but much lower prices overall, as shortages (and the associated high prices) are reduced relative to the StdMC algorithm.

We calculate system costs for each month under the StdMC and RCMC as summarized in Table VI by estimating generators' revenue. The generators' revenue is equal to the market revenue –from energy, reserve, and RC sales- plus uplift payments which compensate generators when market revenue is insufficient to cover both fixed and marginal costs. Uplift 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 uplift 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, uplift payments are 2%-20% lower and total system costs are 12%-30% lower when RC products are included (Fig. 3).

D. Wind Power Curtailment

Wind curtailment is infrequent in the StdMC model and occurs only during the April and July months under high wind penetration. The RCMC model results in fewer instances and lower quantity of wind curtailment: 67% fewer real-time

TABLE VI

COSTS CALCULATIONS FROM OUTPUTS OF STDMC AND RCMC

StdMC	
Generator Costs for unit u during day d $(\mathbf{GC_{u,d}})$= $\sum_{t\in d}\left(\mathrm{Gen}_{u,t}^{RTED}\times \mathrm{MC}_u+\mathrm{SR}_{u,t}^{RTED}\times \mathrm{SRC}_u+\mathrm{Commit}_{u,t}^{DAUC}\times \mathrm{NLC}_u+\mathrm{Started}_{u,t}^{DAUC}\times \mathrm{StartC}_u\right)$	(58)
Generator Market Revenue $(\mathbf{GMR_{u,d}})$= $\sum_{t\in d}(\mathrm{Gen}_{u,t}^{DAED}\times \mathrm{MCPE}_t^{DAED}+\max\left(\mathrm{Gen}_{u,t}^{RTED}-\mathrm{Gen}_{u,t}^{DAED},0\right)\times \mathrm{MCPE}_t^{RTED}+\mathrm{SR}_{u,t}^{DAED}\times \mathrm{MCPSR}_t^{DAED}+\max\left(\mathrm{SR}_{u,t}^{RTED}-\mathrm{SR}_{u,t}^{DAED},0\right)\times \mathrm{MCPSR}_t^{RTED}$	(59)
Generator Uplift Revenue $(\mathbf{GUR_{u,d}})$= $\mathrm{Max}\left\{(\mathrm{GC}_{u,d}-\mathrm{GMR}_{u,d}),0\right\}$	(60)
Generator Total Revenue during a day$(\mathbf{GTR_{u,d}})$= $\mathrm{GMR}_{u,d}+\mathrm{GUR}_{u,d}$	(61)
Uplift Payments to All Generators in month m $(\mathbf{TUG_m})$= $\sum_{d\in m}\sum_{u\in U}(\mathrm{GUR}_{u,d})$	(52)
Total Payments to All Generators in month m $(\mathbf{TPG_m})$= $\sum_{d\in m}\sum_{u\in U}(\mathrm{GMR}_{u,d}+\mathrm{GUR}_{u,d})$	(63)
RCMC	
Equation (59) is modified to include the additional terms:	
$+\sum_{t=1}^{T}\left(\mathrm{UnitRCUP}_{u,t}^{DAED}\times \mathrm{RCUpDCPrice}+\max\left(\mathrm{UnitRCUP}_{u,t}^{RTED}-\mathrm{UnitRCUP}_{u,t}^{DAED},0\right)\times \mathrm{RCUpDCPrice}+\mathrm{UnitRCDown}_{u,t}^{DAED}\times \mathrm{RCDownDCPrice}+\max\left(\mathrm{UnitRCDown}_{u,t}^{RTED}-\mathrm{UnitRCDown}_{u,t}^{DAED},0\right)\times \mathrm{RCDownDCPrice}\right)$	(64)

*Superscripts 'DAUC','DAED' and 'RTED' represent results from the corresponding models (e.g. $\mathrm{Gen}_{u,t}^{DAED}$ represents the average power generation of unit u during time interval t per the day ahead economic dispatch model).

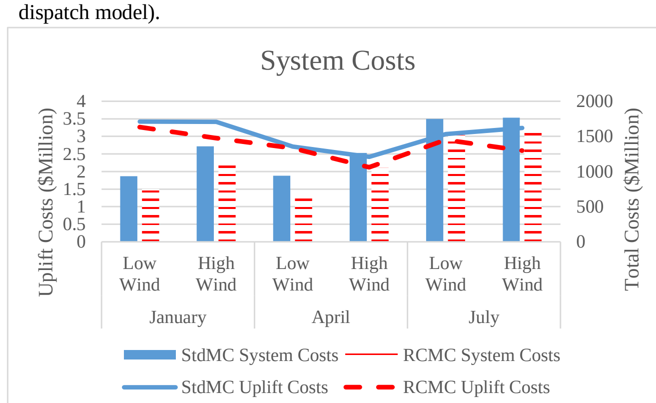

Fig. 3. Uplift costs and system costs. Both are lower with the RCMC algorithm in all month and wind scenarios.

intervals with curtailment in April (27 MWh less) and 20% fewer intervals with curtailment in July (36 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 [21].

E. Generation Fuel Mix and CO2 Emissions

We expected that introducing RC products would cause fuel switching from less flexible coal generators to more flexible natural gas units. This expectation holds true for 4 out of 6 month/wind combinations. RC products reduce coal-fired generation by 0.02% to 0.19% except for the high wind scenarios of January and April when it increases by 0.05% and 0.11% respectively. The exact mechanism causing these change deserves further investigation.

Due in part to this increase in coal use and none or modest reduction in wind curtailment, operational CO2 emissions are higher with RC products relative to the baseline in high wind scenarios of January and April by 0.11% and 0.26%. There is also a small increase in emissions (0.05%) for January under low wind. For the rest of the month/wind scenario combinations RC products reduce CO2 emissions by 0.03% to

0.35%. These small figures may understate the emissions reductions of RCMC for a couple of reasons. First, RC products also result in fewer unit startups which could reduce emissions. Also, RC products reduce wind curtailment, but in our simulations the potential for realizing this benefit is very limited as wind spillage in the StdMC model occurs infrequently even under the high wind scenarios. Until higher wind scenarios are explored or more detailed accounting of start-up emissions is performed we can only conclude that our results demonstrate that the environmental advantages from introducing RC products stem from the facilitation of wind integration, reducing wind curtailment while lowering system costs and increasing reliability, but not necessarily from a direct reduction of CO2 emissions through re-dispatch. In the sensitivity analysis we explore the impacts on emissions and number of startups from increasing the value of the economic benefit assigned to RC.

F. 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 high wind scenario. Table VII shows the changes in the parameters for the sensitivity cases.

TABLE VII
DESCRIPTION OF SENSITIVITY CASES

Sensitivity case	RCUpDCPrice ($/MWh)	RCDownDCPrice ($/MWh)	OverGenPen ($/MWh)	UnderGenPen ($/MWh)	SRScarcityPen ($/MWh)
0. BaseCase 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**

Cases 1, and 2 only change the parameters of the RCMC model but not those of the StdMC.

We first consider the performance of the RCMC model relative to the StdMC model with the same assumptions. As discussed above, under base case assumptions, RCMC results in better reliability, prices, system costs, and generator start-ups relative to StdMC. If the URC/DRC prices are augmented to $15/MWh, the improvement from RCMC is magnified for most performance metrics and all months (sensitivity case 1). This is also true for the changes in parameters considered in sensitivity cases 3-6. For sensitivity case 2, when URC/DRC prices are reduced to $5/MWh, the differences between StdMC and RCMC metrics are generally in favor of RCMC but they are lower than under the base-case assumptions.

This leads us to two observations about the attributes of the RCMC model: a) if URC/DRC prices are lower, the cost and reliability advantages of RCMC over StdMC are reduced, and b) the superior cost and reliability performance of RCMC relative to StdMC holds and is sometimes enhanced when over/under generation penalties and scarcity prices are higher (Table VIII and Table IX).

As in the base case, the impacts on environmental performance of introducing RC products are mixed in the sensitivity cases. RC products cause higher CO2 emissions for the months of January and April for almost all sensitivity cases except April case 2, and January case 5. For July, the reduction of emissions from RC products is magnified with sensitivity cases 3-6. The benefit of a reduction in start-ups observed in the base case is improved or maintained for all sensitivity cases and months except for April.

TABLE VIII
RELATIVE CHANGES IN COSTS AND PRICES

Case	Results as differences between standard and flex ramp models with same assumptions (StdMC - FlexRMC) for high wind scenarios														
	System Costs (Million USD)			Uplift						Average Market Clearing Price ($/MWh)					
				No. of instances			Payment (Million USD)			Overall			Non-shortage intervals		
	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul
Base	194	216	213	415	92	393	0.5	0.3	0.7	80	122	93	-1.8	-2.2	-2.7
1	211	283	477	591	254	378	0.6	0.3	0.6	87	159	184	-3.0	-3.1	-5.1
2	89	149	129	27	-353	23	0.2	0.1	0.4	33	85	60	-0.7	-0.9	-0.9
3	193	237	209	415	146	379	0.5	0.3	0.7	83	139	90	-1.8	-2.20	-2.6
4	257	249	237	321	172	396	0.4	0.3	0.7	108	141	101	-1.9	-2.18	-2.6
5	253	405	301	412	250	361	0.4	0.3	0.7	113	218	125	-1.8	-1.99	-2.7

Relative changes in monthly generator's total revenue TPG_m, uplift payments $TUG_m$and Market Clearing Prices $MCPE$ between StdMC and RCMC models for scenarios with same assumptions.

Legend			
Improvement due to ramp products		Deterioration due to ramp products	
Improvement is greater than under base case	Improvement is less than under base-case	Deterioration is less than under base case	Deterioration is greater than under base case

TABLE IX
RELATIVE CHANGES IN ENVIRONMENTAL AND RELIABILITY METRICS

Case	Results as differences between standard and flex ramp models with same assumptions (StdMC - RCMC) for high wind scenarios											
	CO2 Emissions (in 1000 tons)			Total Number of generator startups			Reserve Scarcity					
							No. of instances			Reserve Scarcity in 1000 MW		
	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul	Jan	Apr	Jul
Base	-17.3	-31.0	5.2	0	6	15	222	357	289	12	17	28
1	-45.0	-40.4	2.4	2	-1	19	233	415	534	14	30	66
2	-14.5	0.3	9.8	7	-8	11	144	321	185	3	15	14
3	-23.0	-53.9	11.3	6	-3	14	226	383	299	14	21	28
4	-0.8	-29.4	13.1	15	1	14	254	320	298	16	17	27
5	4.6	-22.2	12.6	20	37	15	255	388	308	16	24	27

Changes in CO_2 emissions (not including start-up emissions), total number of generator start-ups and reserve scarcity from RCMC relative to StdMC for scenarios with same assumptions. Same color-coding as in Table VIII.

V. CONCLUSION

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], [5], our simplified model allows us to conduct parametric analysis of shortage penalty prices, ramp-capability demand curve, target levels of spinning reserve and RC, and forecast errors for wind and load to determine ways in which these parameters can be tuned to enhance the performance of RC products.

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 support MISO's anticipated benefits of the RC products under a range of system conditions and pricing parameters.

VI. Acknowledgment

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Adam Cornelius received the B.A. degrees in Mathematics and in Political Science from Colorado College, Colorado Springs, CO, USA, in 2003, and the M.E.M. degree in Energy and the Environment from Duke University, Durham, NC, USA, in 2014.
He is currently an Energy Industry Analyst at the Federal Energy Regulatory Commission, Washington, DC, USA, where he is engaged in oversight of electric power markets.

Rubenka Bandyopadhyay received a B.Tech in electrical engineering in 2010 from the West Bengal University of Technology, India and an M.S. degree in electrical and computer engineering in 2011 from Duke University, USA. She is currently a PhD student working on energy policy with a focus on electric power systems at the Nicholas School of the Environment at Duke University.

Dalia Patiño-Echeverri received B.S. and M.Sc. degrees in Industrial Engineering from University of The Andes, Bogotá, Colombia and the PhD degree in Engineering and Public Policy from Carnegie Mellon University, Pittsburgh, PA, USA. She is currently assistant professor at the Nicholas School of the Environment at Duke University, where she studies the impact that different power generation technologies, market rules, and policies have on investment and operations in the electricity industry.