Swing Contracts with Dynamic Reserves for Flexible Service Management

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Abstract—The increasing penetration of variable energy resources in modern electric power systems requires additional flexibility in reserve provision to maintain reliable and efficient grid operations. However, full recognition and appropriate compensation of this flexibility is difficult to ensure within current power market designs due to rigidity in reserve definitions and requirements. This paper proposes a new mixed-integer linear programming (MILP) formulation for the optimal clearing of a day-ahead market based on swing contracts with dynamically updated regulation reserve zones. Five-bus and thirty-bus test cases are used to illustrate the effectiveness of the proposed new market design.

Index Terms—Day-ahead market, swing contract, dynamic regulation reserve zones, flexible service provision, MILP optimization

Nomenclature

Sets and Indices

$\mathcal{B}$: Set of bus indices b

$\mathcal{B}(z) \subset \mathcal{B}$: Subset of buses in reserve zone z

$\mathcal{L} \subset \mathcal{B} \times \mathcal{B}$: Set of transmission line indices ℓ

$\mathcal{L}_{O(b)}$: Subset of lines ℓ originating at bus b

$\mathcal{L}_{E(b)}$: Subset of lines ℓ ending at bus b

$\mathcal{M}$: Set of indices m for power market participants with dispatchable energy resources

$\mathcal{M}(b) \subset \mathcal{M}$: Market participants with dispatchable energy resources at bus b

$\mathcal{M}(z) \subset \mathcal{M}$: Market participants with dispatchable energy resources in reserve zone z

$\mathcal{P}$: Range of down/up power levels p in a swing contract

$\mathcal{R}$: Range of down/up ramp rates r in a swing contract

$\mathcal{S}$: Set of net load scenarios s

$\mathcal{T}$: Set of hour indices $t = 1, \ldots, T$

$\mathcal{Z}$: Set of regulation reserve zone indices z

Parameters and Functions

$A_m(t)$: Binary service offer indicator: 1 if m in hour t is within its contract service period; 0 otherwise

$B(\ell)$: Inverse of reactance $X(\ell)$ (pu) for line ℓ

$\widehat{d}$: ISO's estimate for the max % deviation of zonal net load above and below its forecasted value (decimal %)

Δt: Time-period length (one hour)

$E(\ell)$: End bus for line ℓ

Λ_1: Imbalance penalty ($/MWh) for excess power

Λ_2: Imbalance penalty ($/MWh) for a power deficit

$NL_b(t)$: Net load (MW) at bus b during hour t

$\widehat{NL}_b(t)$: Net load forecast (MW) for bus b during hour t

$O(\ell)$: Originating bus for line ℓ

$P_\ell^{\max}$: Line flow limit (MW) for line ℓ

$P_m^{\min}$: Lower power limit (MW) for m

$P_m^{\max}$: Upper power limit (MW) for m

ϕ: Swing contract performance payment method

$\phi_m(t)$: Energy price ($/MW\Delta t$), a simple form of performance payment method for real-time service offered by m in SC_m

π_m^o: Offer price ($) requested by m for a swing contract

ref: Designated angle reference bus

R_m^D: Ramp-down limit (MW/Δt) for m

R_m^U: Ramp-up limit (MW/Δt) for m

SC_m: Swing contract offered into an SC DAM by m

S_o: Positive base power (in three-phase MVA)

ISO Control Variables for SC DAM Optimization

$p_m(t)$: Power output (MW) of m during hour t

x_m: Binary cleared contract indicator: 1 if the swing contract offered by m is cleared; 0 otherwise

$\theta_b(t)$: Voltage angle (radians) at bus b during hour t

Solution Values Derived from SC DAM Optimization

$\overline{p}_m(t)$: Max available power output (MW) of m during t

$\underline{p}_m(t)$: Min available power output (MW) of m during t

$\overline{P}_\ell(t)$: Line power (MW) for line ℓ during t

$RR_z^L(t)$: Lower regulation reserve requirement (MW) at reserve zone z during t

$RR_z^U(t)$: Upper regulation reserve requirement (MW) at reserve zone z during t

$v_m(t)$: Binary unit commitment indicator derived from x_m and $A_m(t)$: 1 if m is online in hour t; 0 otherwise

$\alpha_b^+(t)$: Non-negative slack variable indicating excess power (MW) at bus b during t

$\alpha_b^-(t)$: Non-negative slack variable indicating a power deficit (MW) at bus b during t

I. Introduction

VARIABLE energy resources (VERs), such as wind and solar power, cannot be closely controlled to match changes in load or to meet other system requirements. The growing participation of VERs in U.S. centrally-managed wholesale power markets has increased the volatility of net load, i.e., load minus non-dispatchable generation. This, in turn, has increased the importance of flexible reserve provision to ensure the continual balancing of net load [1].

To date, however, several important reserve issues still need to be resolved. One issue is that reserves are variously defined and compensated across different markets [2]. This lack of standardization makes it difficult to evaluate and compare the reliability, efficiency, and fairness of reserve arrangements across these markets.

A second issue is appropriate compensation for flexibility in reserve provision [3]. Reserve types are typically defined in broad rigid terms (e.g., regulation, spinning reserve). These definitions do not permit reserves to be further differentiated and compensated on the basis of additional valuable flexibility, such as an ability to ramp up and down between minimum and maximum values over very short time intervals.

A third issue is that attempts to introduce new reserve products have led some energy regions to resort to out-of-market (OOM) compensation processes. The additional complexity resulting from OOM compensation processes provides increased opportunities for market participants to gain unfair profit advantages through strategic behaviors [4].

A fourth issue is that valued services provided by energy resources in power systems largely arise from one source: generated power paths. Since the attributes of power paths are highly correlated, attempts to unbundle these attributes into separately defined and priced products are conceptually problematic. For example, how can "ramping" be properly valued apart from a consideration of other power path attributes, such as start time, duration, and power range?

In response to these issues, a group of researchers at Iowa State University and Sandia National Laboratories have proposed a new swing-contract (SC) market design as a robust-control design for centrally-managed wholesale power markets [5], [6]. "Swing" refers to range-flexibility in offered services.

More precisely, an SC permits the owner of a dispatchable energy resource to offer into a centrally-managed power market a collection of possible power paths with a wide range of attributes, thus permitting greater flexibility in real-time dispatch to service both power and reserve needs. Permitting the owner to offer services in correlated form, as a collection of possible power paths, helps to ensure that all of the owner's offered services receive appropriate compensation.

Subsequent studies [7]–[9] have demonstrated the practical feasibility of the SC market design for day-ahead markets (DAMs). Mixed Integer Linear Programming (MILP) formulations are developed for the optimal clearing of an SC DAM subject to standard system constraints and system-wide reserve requirements. These MILP formulations are solved using existing MILP software with computational times that compare favorably with current DAM optimization formulations.

Nevertheless, the reliance of these SC DAM optimization formulations on rigidly pre-specified system-wide reserve requirements is not consistent with the basic goal of SC market design: namely, to promote flexible service provision. In practice, grid congestion varies over time; and grid congestion can hinder the ability of a system operator to ensure delivery of reserves to zones where power is needed to balance actual real-time net load.

This study modifies the SC DAM optimization formulation in ref. [8] in three principal ways. First, the SC DAM constraints are extended to include hourly zonal constraints for regulation reserves.[1] These constraints impose endogenously generated upper and lower hourly zonal reserve requirements, conditional on hourly forecasted net loads. Second, the reserve zones are adjusted on a daily basis, immediately prior to each SC DAM optimization. This adjustment is accomplished by means of a weighted average of shift factor differences, which in turn is based on a newly developed line-congestion risk index. Third, the objective function is extended to permit a cost evaluation for any needed real-time imbalance adjustments (e.g., load curtailments).

Comparative performance tests conducted with five-bus and thirty-bus systems are used to illustrate the effectiveness and practicality of our proposed SC DAM optimization with dynamically adjusted reserve zones. Performance is measured in terms of three costs: (i) payments of offer prices to issuers of cleared SCs for service availability; (ii) ex-post compensation to issuers of cleared SCs for any next-day services actually performed; and (iii) ex-post costs arising from any needed next-day imbalance adjustments (e.g., load curtailments).

The relation of this study to the existing dynamic reserve literature is discussed in Section II. The basic form of a swing contract (SC) and an SC DAM are reviewed in Section III.

Section IV provides an analytical formulation for our extended SC DAM optimization with regulation reserve zones. Section V explains our proposed new method for the daily updating of these zones. Section VI outlines our performance testing procedure. Key performance outcomes are reported in Sections VII and VIII. Concluding remarks are given in Section IX. Technical details regarding our data-based construction of net load scenarios and our determination of performance metrics are provided in Appendices A and B.

II. RELATION TO PREVIOUS DYNAMIC RESERVE WORK

A dynamic reserve method is any process permitting the run-time adjustment of reserve demands for electric power market operations. Dynamic reserve methods currently under exploration include the adaptive updating of reserve requirement levels, reserve demand curves, reserve disqualification indicators, and reserve zone designations [10].

Dynamic reserve methods are particularly promising for dealing with potential power imbalances caused by high penetration of VERs [11]–[15]. For example, ref. [11] investigates whether the adaptive modification of a targeted reserve capacity over time based on expected system conditions can avoid expensive overestimation of reserve requirements, given a power system with high levels of wind power. Ref. [12] proposes a heuristic rule to define dynamic reserve requirements: reserves should be no less than 3% of load and 5% of forecasted renewable generation.

However, recent research has stressed the need to consider more carefully the effects of VERs on reserve deliverability.

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[1]By "regulation reserves" we mean power capacity subject to secondary frequency control for routine net load balancing purposes. Secondary frequency control is a central automatic process for the communication of power-command signals, generally referred to as Automatic Generation Control (AGC) in the U.S.; see [2, Sec. 2]. In this study we do not consider the need for contingency reserves to meet low-probability high-impact events that result in temporary unusually-high variation in net load.

U.S. centrally-managed DAMs rely on pre-specified reserve zones in an attempt to ensure that reserves are available to meet power needs. A reserve zone is a portion of the grid that experiences relatively infrequent internal transmission congestion (binding line-limits). However, given increasingly volatile net loads, line-limits can hinder reserve deliverability even within these pre-specified reserve zones.

One promising approach for improving reserve deliverability is the adaptive updating of reserve zones based on system conditions, including net load uncertainties. Previous researchers have proposed various metrics for this purpose.

For example, ref. [16] proposes an electrical distance (ED) metric. However, the ED metric cannot be used to determine reserve zones for standard DAM optimization formulations, for which voltage magnitudes are assumed to be 1pu.

Refs. [17], [18] develop methods permitting market operators to dynamically adjust contingency reserve zones. These methods are based on a metric constructed as an adaptively updated weighted average of power transfer distribution factor (PTDF) differences[2] that assigns larger weights to lines that frequently operate close to their limits. Reserve zones are determined using a K-means clustering algorithm that makes use of this metric, where the goal is to protect against sudden generator contingencies.

In this study we develop a modified version of the dynamic reserve methods proposed in refs. [17], [18] that can be used to determine daily updated regulation reserve zones for the SC DAM based on past congestion conditions. As detailed in Section V, the three key modifications are: (i) a focus on regulation reserves for routine net load balancing purposes; (ii) use of a different dissimilarity metric (incorporating a newly developed line congestion risk index) to measure the dissimilarity of buses and bus subsets; and (iii) use of a hierarchical clustering method based on this dissimilarity metric to partition the set of grid buses into regulation reserve zones.

III. THE BASIC SC DAM DESIGN

A. Swing Contracts: Overview

A *swing contract (SC)* permits the owner of a dispatchable[3] energy resource to offer into a centrally-managed wholesale power market a collection $\mathbb{P}$ of potential power paths enabling "swing" (flexibility) in service provision. For example, the offered power paths can provide flexibility with regard to start-up location, start-up time, down/up power amplitude, ramp rate, duration, volt/VAr support, and energy storage capacity.[4]

The offer price π^o of an SC is an insurance premium, i.e., a payment requested by the SC seller for ensuring the

availability of a collection of power paths to meet uncertain *future* power and reserve needs. If an offered SC is cleared by the market manager, the SC seller is immediately paid the SC's offer price. If a power path from $\mathbb{P}$ is then subsequently dispatched in real-time operations for *actual service performance*, the SC seller is further compensated ex post in accordance with the performance payment method ϕ that the SC seller has included among the SC's contractual terms.

SCs can take either a firm or option form. A cleared SC in firm form is a non-contingent contract that imposes obligations on both the SC seller and the market manager. The market manager must procure a power path from the SC seller in accordance with the SC's contractually specified terms, and the SC seller is obligated to deliver this power path to the market manager. In contrast, a cleared SC in option form gives the market manager the right, but not the obligation, to exercise the SC by a contractually specified exercise time. If exercised, the cleared SC becomes firm.

SCs in firm form are recommended for routine net load balancing purposes, while SCs in option form are recommended for protection against low-probability high-impact contingencies such as line or generator outages. See [5], [6] for further discussion of these points.

B. Specific Swing Contract Formulation

As in [7], [8], this study focuses on firm SCs that permit the owner of a dispatchable energy resource to offer swing (flexibility) in power levels and ramp rates to facilitate routine net load balancing in a centrally-managed wholesale power market. The specific form assumed for these SCs is as follows:

$$\text{SC} = [b, t_s, t_e, \mathcal{P}, \mathcal{R}, \phi] \tag{1}$$

b = bus location where service delivery is to occur;

t_s = power delivery start time;

t_e = power delivery end time;

$\mathcal{P} = [P^{\min}, P^{\max}]$ = range of down/up power levels p;

$\mathcal{R} = [-R^D, R^U]$ = range of down/up ramp rates r;

ϕ = Performance payment method for real-time services.

As illustrated in Fig. 1, the location b in (1) refers to a particular bus of a transmission grid. The start and end times t_s and t_e denote specific calendar times expressed at the granularity of hours t, with $t_s < t_e$. The power interval bounds $P^{\min} \leq P^{\max}$ can represent pure power injections (if $0 \leq P^{\min}$), pure power withdrawal or absorption (if $P^{\max} \leq 0$), or bi-directional power capabilities (if $P^{\min} \leq 0 \leq P^{\max}$). The down/up limits $-R^D$ and R^U for the ramp rates r (MW/Δt) are assumed to satisfy $-R^D \leq 0 \leq R^U$.

The location b, the start time t_s, and the end time t_e are all specified as single values in (1). However, the power levels p and the down/up ramp rates r are specified in swing form with associated ranges $\mathcal{P}$ and $\mathcal{R}$.

The performance payment method ϕ in (1) designates the mode of ex post compensation to be paid to the seller of the SC if this seller is called upon to perform actual real-time services. As detailed in refs. [5]–[8], this performance payment method can take a wide variety of forms.

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[2]A power transfer distribution factor PTDF$(\ell, \Delta p, b_s, b_k)$ measures the change in power flow on a power line ℓ resulting from a power increment Δp injected at a source bus b_s and withdrawn at a sink bus b_k [19].

[3]The qualifier "dispatchable" means that the energy resource must be able to follow a time-varying Automatic Generation Control (AGC) signal as long as the required power path remains within contractually specified limits.

[4]For detailed discussion and illustrations for a wide variety of swing contract forms, see ref. [5]. For example, the general representation for a swing option contract provided in ref. [5, Sec. 3.4.2] includes energy capacity (e_{cap}) as a possible service attribute to handle energy storage resources. A numerical example of a swing option contract designed for an energy storage plant is given in [5, App. A.5,p. 37].

b = bus b;
t_s = 8:00am;
t_e = 10:00am;
$\mathcal{P} = [P^{min}, P^{max}] = [10\text{MW}, 40\text{MW}]$;
$\mathcal{R} = [-R^D, R^U] = [-38\text{MW/h}, 28\text{MW/h}]$;
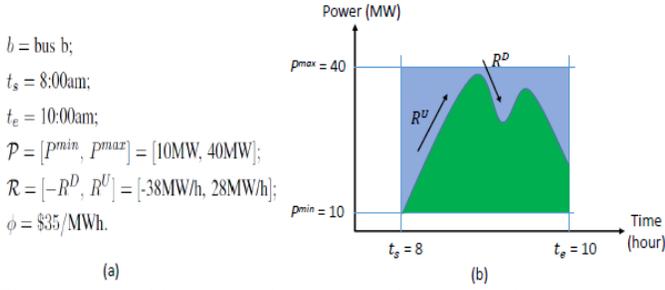$\phi = \$35/\text{MWh}$.

(a)

(b)

Fig. 1.   (a) An illustrative swing contract with power and ramp-rate swing offered by a dispatchable energy resource into a centrally-managed wholesale power market; (b) A possible power path the market manager could signal the resource to follow during next-day operations. The area under this power path, if followed, is delivered energy (MWh) that must be compensated ex post at the rate $\phi = \$35/\text{MWh}$.

For example, as illustrated in Fig. 1, ϕ could designate a price ($/MWh) to be applied to the total amount of energy (MWh) supplied to the grid between t_s and t_e. Alternatively, ϕ could specify that the price to be paid for power injected into the grid between t_s and t_e is contingent upon the realization of future events, such as a spot fuel price between t_s and t_e.

Moreover, ϕ could include required compensation for ramping services calculated by means of some form of "mileage" metric based on the length of any delivered down/up power path. In addition, ϕ could include penalty or incentive payments to encourage accurate following of dispatch instructions between t_s and t_e, thus permitting a market-based determination of these payments.

C. SC DAM Design: Basic Formulation

An SC DAM is a forward market managed by an Independent System Operator (ISO) that permits owners of dispatchable energy resources to submit SCs offering possible next-day service performance. The goal of the ISO is to minimize the cost of clearing (accepting) a sufficient number of SC offers to ensure balancing of uncertain next-day net loads. To retain the ISO's non-profit status, all costs incurred by the ISO for SC procurement and use are passed through to load-serving entities (LSEs) in proportion to their share of serviced real-time loads.

Let $\mathcal{M}$ denote the set of all participants in the SC DAM that own dispatchable energy resources. Suppose a participant $m \in \mathcal{M}$ submits a swing-contract SC_m to the SC DAM along with a requested offer price π_m^o, set by m. If SC_m is cleared by the ISO, m is immediately paid his offer price π_m^o. If m's energy resource is subsequently dispatched to perform next-day real-time services in accordance with SC_m, ex-post compensation is paid to m for these services in accordance with the performance payment method ϕ_m that m has included among the terms of SC_m.

It is the responsibility of market participant m to guarantee the financial feasibility of his offered swing contract SC_m. Two aspects must be considered.

First, m should make sure that his offer price π_m^o is sufficient to cover all of the costs that m would have to incur to guarantee service *availability* in accordance with SC_m. Examples of service availability costs include unit commitment costs (e.g., start-up and no-load costs) as well as "lost opportunity costs" arising from m's inability to receive revenues from a next-best alternative use of his energy resource.

Second, m should make sure that his performance payment method ϕ_m is sufficient to cover, ex post, all of the costs that m would have to incur if called upon to perform actual real-time services in accordance with SC_m. Examples of service performance costs include fuel and labor costs arising from actual power generation.

An important point to stress is that an SC DAM is purely a day-ahead planning device for the ISO and the market participants. If a market participant $m \in \mathcal{M}$ has submitted a swing contract S_m to a day-D SC DAM, the only information that m receives back from the ISO at the end of this DAM is whether or not S_m has been cleared; the ISO makes no changes to this contract. If S_m is cleared, this means that m is now obligated (committed) to ensure that, during the following day D+1, his energy resource will be able to follow a time-varying AGC power dispatch signal as long as the required power path is permissible under the terms of S_m.

As demonstrated in Section IV, a Mixed Integer Linear Programming (MILP) cost-minimization optimization can be used to determine which SCs submitted to a day-D SC DAM are cleared, subject to system and reserve constraints. This in turn determines which market participants $m \in \mathcal{M}$ are obligated to ensure service availability during day D+1.

In contrast, current U.S. ISO-managed DAMs use two types of optimization to plan for next-day operations [20, Chpts. 2-3]. First, Security-Constrained Unit Commitment (SCUC) is used to determine binary (yes/no) Unit Commitment (UC) status for each generation unit at each bus for each hour. Second, Security-Constrained Economic Dispatch (SCED) is used to determine a Locational Marginal Price (LMP) and scheduled generation dispatch levels at each bus for each hour. SCUC is formulated as a MILP problem, and SCED is typically formulated as a linear programming problem.

		Standard DAM	SC DAM
Similarities		• Conducted day-ahead to plan for next-day operations • ISO-managed • Participants include LSEs & dispatchable energy resources • Subject to same system constraints: e.g. transmission, generation, ramping, & power-balance constraints	
Differences	• Optimization formulation	SCUC & SCED	Swing contract clearing
	• Settlement	Locational marginal pricing	Contract-determined prices
	• Payment	Payment for next-day service before actual performance	Payment for availability now & performance ex post
	• Out-of-market payments	Make-whole payments (e.g., for unit commitment)	No out-of-market payments
	• Info released to participants	UC, DAM LMPs, & next-day dispatch schedule	Which swing contracts have been cleared

Fig. 2.   Basic attribute comparison of the SC DAM and standard U.S. DAMs.

Comparisons of basic attributes and optimization formulations for the SC DAM and current U.S. DAMs are given in Figs. 2 and 3. As indicated, three basic advantages of the SC DAM are as follows: (i) a two-part pricing design that permits

Fig. 3. Comparison of SC DAM optimization and standard U.S. DAM SCUC/SCED optimizations.

full separate market-based compensation for service availability (insurance) and actual real-time service performance; (ii) no reliance on out-of-market (OOM) payments; and (iii) no payments for performance ahead of actual performance.

IV. SC DAM OPTIMIZATION FORMULATION WITH REGULATION RESERVE ZONES

Our MILP formulation for an SC DAM optimization with regulation reserve zones is illustrated below. For concreteness, this illustration is based on the following eleven assumptions:

(A1) The SC DAM takes place on day D in order to plan for routine net load balancing on day D+1.

(A2) The 24-hours of day D+1 are represented by $\mathcal{T} = \{1, \ldots, 24\}$ with $\Delta t = 1$h.

(A3) All loads are fixed (must-serve) loads that do not provide dispatchable services.

(A4) All loads are serviced by Load-Serving Entities (LSEs).

(A5) An LSE's SC DAM demand bid at any load bus b for hour t of day D+1 consists of a fixed (price-insensitive) power demand $\widehat{L}_b(t, \text{D+1})$ reflecting the LSE's load forecast for bus b during hour t of day D+1.[5]

(A6) The ISO forms a wind power forecast $\widehat{W}_b(t, \text{D+1})$ for bus b during hour t of day D+1 for any bus b that has wind generation.

(A7) The ISO forms a net load forecast $\widehat{NL}_b(t, \text{D+1})$ for bus b during hour t of day D+1 by subtracting the ISO's wind power forecast $\widehat{W}_b(t, \text{D+1})$ (if any) from the LSE load forecast $\widehat{L}_b(t, \text{D+1})$ (if any).

(A8) The ISO expects next-day net load at different buses during successive hours to lie within a $\widehat{d}\%$ band above and below forecasted net load.

(A9) Each $m \in \mathcal{M}$ (i.e., each market participant with a dis-

patchable energy resource) offers a single[6] swing contract SC_m into the SC DAM, where SC_m takes form (1).

(A10) The performance payment method ϕ_m appearing within SC_m takes the form of a collection of flat-rate energy prices $\phi_m(t)$ ($/MW$\Delta t$), one price for each hour $t \in \mathcal{T}$.

(A11) The only reserves considered in the SC DAM are regulation reserves for routine net load balancing.

The optimization problem to be solved by the ISO managing the day-D SC DAM is then as follows: Given forecasted net loads for day D+1, select appropriate control variables to minimize the total cost ($) of SC acquisition for the servicing of next-day power and reserve needs subject to system and reserve constraints. The various components of this optimization problem will next be presented in careful analytical form.[7]

1) ISO control variables:

$$\{x_m, p_m(t), \theta_b(t) \mid m \in \mathcal{M}, t \in \mathcal{T}, b \in \mathcal{B}\} \quad (2)$$

2) Total Cost Objective Function::

$$\sum_{m \in \mathcal{M}} \pi_m^o x_m + \sum_{t \in \mathcal{T}} \sum_{m \in \mathcal{M}} \phi_m(t) |p_m(t)| \Delta t$$
$$+ \left(\Lambda_1 \sum_{b \in \mathcal{B}} \sum_{t \in \mathcal{T}} \alpha_b^+(t) \Delta t + \Lambda_2 \sum_{b \in \mathcal{B}} \sum_{t \in \mathcal{T}} \alpha_b^-(t) \Delta t \right) \quad (3)$$

Given any choice of the ISO's control variables, total cost (3) is the summation of three components: (i) offer price payments π_m^o to be made immediately to sellers m of cleared SCs (x_m=1) as compensation for their assurance of next-day service availability; (ii) expected performance payments to be made ex post to sellers of cleared SCs for next-day deliveries of down/up power; and (iii) expected imbalance payments to be made the next day to handle real-time discrepancies between net loads and scheduled power availability.

Costs (ii) and (iii) are expected costs because they are based on expected (forecasted) next-day net loads. Cost (iii) is an expected approximate valuation of the cost to be incurred the next day to handle real-time imbalance, as measured by the slack variables $\alpha_b^+(t)$ and $\alpha_b^-(t)$ appearing below in the SC DAM power balance constraints (9).[8]

3) Unit commitment constraints:

$$v_m(t) = x_m A_m(t), \forall m \in \mathcal{M}, t \in \mathcal{T} \quad (4)$$

The unit commitment $v_m(t) \in \{0, 1\}$ for each market participant $m \in \mathcal{M}$ for each hour t of day D+1 is determined by two variables: the cleared contract indicator $x_m \in \{0, 1\}$; and the service offer indicator $A_m(t) \in \{0, 1\}$. The indicator $A_m(t)$ is a derived value, calculated by the ISO from the information provided within SC_m. For example, suppose SC_m specifies that services can be provided by m during the time interval $[t_s, t_e] = [10, 19]$ on day D+1. Then $A_m(t) = 1$ if

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[5]Although LSEs participating in U.S. DAMs are permitted to submit hourly demand bids for the next-day power needs of their customers that include a price-sensitive portion, most LSE hourly demand bids take a fixed form. For example, the percentage of cleared price-sensitive demand in ISO-New England's DAM has remained nearly constant at 27% from 2012-2016; see [21, Fig. 3-20]. Presumably this will change as metering technology advances encourage the increased implementation of demand response initiatives.

[6]More generally, market participants with dispatchable energy resources could submit *portfolios* of SCs into an SC DAM; see [6] for numerical illustrations of SC DAM market clearing with SC portfolio offers.

[7]See the Nomenclature table for precise symbol meanings.

[8]For example, given a real-time power deficit, the ISO might have to resort to load curtailment or to unscheduled dispatch of expensive fast-start fast-ramp peaker units. Conversely, given a real-time excess of power, the ISO might have to pay for additional load absorption as an ancillary service.

$t \in \{10, \ldots, 19\}$ and $A_m(t) = 0$ if $t \in \{1, \ldots, 9, 20, \ldots, 24\}$. Participant m is committed to be available for service provision during hour t of day D+1 if and only if both x_m and $A_m(t)$ in (4) equal 1.

4) Voltage angle limits:

$$\theta_{\text{ref}}(t) = 0, \ \forall t \in \mathcal{T} \tag{5}$$

$$-\pi \leqslant \theta_b(t) \leqslant \pi, \ \forall b \in \mathcal{B}, t \in \mathcal{T} \tag{6}$$

Constraints (5) determine the voltage angle at the designated angle reference bus ref for all hours t, and constraints (6) impose voltage angle limits at all buses for all hours t.

5) Line power transmission constraints:

$$P_\ell(t) = S_0 B(l) \left[\theta_{O(\ell)}(t) - \theta_{E(\ell)}(t)\right], \ \forall \ell \in \mathcal{L}, t \in \mathcal{T} \tag{7}$$

$$-P_\ell^{\text{max}} \leqslant P_\ell(t) \leqslant P_\ell^{\text{max}}, \ \forall \ell \in \mathcal{L}, t \in \mathcal{T} \tag{8}$$

6) Power balance constraints at each bus:

$$\sum_{m \in \mathcal{M}(b)} p_m(t) + \sum_{\ell \in \mathcal{L}_{E(b)}} P_\ell(t) = \widehat{NL}_b(t, \text{D+1})$$
$$+ \sum_{\ell \in \mathcal{L}_{O(b)}} P_\ell(t) + \alpha_b^+(t) - \alpha_b^-(t), \ \forall b \in \mathcal{B}, t \in \mathcal{T} \tag{9}$$

7) Market participant capacity constraints:

$$\underline{p}_m(t) \leqslant p_m(t) \leqslant \overline{p}_m(t), \ \forall m \in \mathcal{M}, t \in \mathcal{T} \tag{10}$$

$$\overline{p}_m(t) \leqslant P_m^{\text{max}} v_m(t), \ \forall m \in \mathcal{M}, t \in \mathcal{T} \tag{11}$$

$$\underline{p}_m(t) \geqslant P_m^{\text{min}} v_m(t), \ \forall m \in \mathcal{M}, t \in \mathcal{T} \tag{12}$$

8) Market participant ramp-up and ramp-down constraints:

$$\overline{p}_m(t) - p_m(t-1) \leqslant R_m^U \Delta t v_m(t-1)$$
$$+ P_m^{\text{max}}[1 - v_m(t-1)], \ \forall m \in \mathcal{M}, t = 2, \ldots T \tag{13}$$

$$p_m(t-1) - \underline{p}_m(t-1) \leqslant R_m^D \Delta t v_m(t)$$
$$+ P_m^{\text{max}}[1 - v_m(t)], \ \forall m \in \mathcal{M}, t = 2, \ldots T \tag{14}$$

9) Zonal reserve requirement constraints:

$$\sum_{m \in \mathcal{M}(z)} \left[\overline{p}_m(t) - p_m(t)\right] \geqslant RR_z^U(t), \forall t \in \mathcal{T}, z \in \mathcal{Z} \tag{15}$$

$$\sum_{m \in \mathcal{M}(z)} \left[p_m(t) - \underline{p}_m(t)\right] \geqslant RR_z^L(t), \forall t \in \mathcal{T}, z \in \mathcal{Z} \tag{16}$$

$$RR_z^U(t) \geqslant \widehat{d} \cdot \sum_{b \in \mathcal{B}(z)} \widehat{NL}_b(t, \text{D+1}), \forall t \in \mathcal{T}, z \in \mathcal{Z} \tag{17}$$

$$RR_z^L(t) \geqslant \widehat{d} \cdot \sum_{b \in \mathcal{B}(z)} \widehat{NL}_b(t, \text{D+1}), \forall t \in \mathcal{T}, z \in \mathcal{Z} \tag{18}$$

Constraints (15)-(18) impose upper and lower regulation reserve requirements $RR_z^U(t)$ and $RR_z^L(t)$ for each zone z and hour t. These requirements are endogenously generated as part of the optimal solution, with lower bounds determined by the hourly net load forecasts $\widehat{NL}_b(t, \text{D+1})$ and the ISO's estimate $\widehat{d}$ for the maximum deviation of zonal net load above and below its forecasted value.

10) System-wide reserve requirement constraints:

$$\sum_{m \in \mathcal{M}} \overline{p}_m(t) \geqslant \sum_{b \in \mathcal{B}} \widehat{NL}_b(t, \text{D+1}) + \sum_{z \in \mathcal{Z}} RR_z^U(t), \forall t \in \mathcal{T} \tag{19}$$

$$\sum_{m \in \mathcal{M}} \underline{p}_m(t) \leqslant \sum_{b \in \mathcal{B}} \widehat{NL}_b(t, \text{D+1}) - \sum_{z \in \mathcal{Z}} RR_z^L(t), \forall t \in \mathcal{T} \tag{20}$$

Constraints (19)-(20) represent system-wide regulation reserve requirements for each hour t.

As in [8], the system inherent reserve range (SIRR) for hour t can be calculated as a function of the solution for the SC DAM optimization: $SIRR(t) = [RR^{\text{min}}(t), RR^{\text{max}}(t)]$, where

$$RR^{\text{max}}(t) = \sum_{m \in \mathcal{M}} \overline{p}_m(t), \ \forall t \in \mathcal{T} \tag{21}$$

$$RR^{\text{min}}(t) = \sum_{m \in \mathcal{M}} \underline{p}_m(t), \ \forall t \in \mathcal{T} \tag{22}$$

V. Dynamic Reserve Zone Updating Method

A. Method Overview

In this section we propose a modified version of the dynamic reserve method developed in refs. [17], [18] that can be used to generate daily updated reserve zone specifications for the SC DAM presented in Section IV. The reformulated SC DAM optimization with incorporation of this dynamic reserve method is depicted in Fig 4.
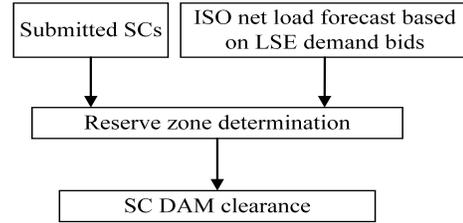

Fig. 4.   Market clearing procedure for the reformulated SC DAM

Our proposed dynamic reserve method consists of four steps to be carried out immediately prior to the operation of the SC DAM on the morning of each day D:

Step 1. *Dual Variable Solutions:* Given a set $\mathcal{F}$ of possible net load forecasts f for day D+1, together with estimated probabilities $\widehat{\text{Prob}}(f)$, use off-line preliminary optimizations to determine dual variable solutions for each transmission line.

Step 2. *Line Congestion Risk Indices:* Given these dual variable solutions, construct a congestion risk index for each transmission line.

Step 3. *Shift Factor Index:* Given these congestion risk indices, construct a matrix SFWA whose elements are weighted averages of shift factor differences.[9]

Step 4. *Reserve Zone Specification:* Given SFWA, use a hierarchical clustering algorithm to partition the set of buses into regulation reserve zones for use in the day-D SC DAM.

These four steps will next be explained in greater detail.

[9]As explained in [19], a shift factor $\text{SF}(\ell, \Delta p, b_s, \text{ref})$ differs from a PTDF with regard to the specification of the sink bus. For shift factors, the sink bus is always designated to be a fixed reference bus, here denoted by ref.

B. Dual Variable Solutions

First, for each net load forecast $f \in \mathcal{F}$, solve the SC DAM optimization in Section IV assuming the set $\mathcal{B}$ of all buses constitutes a single reserve zone. Record the resulting 0-1 cleared contract indicator solutions x_m^f for each $m \in \mathcal{M}$ and f in F for this one-zone benchmark case.

Next, for each net load forecast $f \in \mathcal{F}$: (i) re-solve the SC DAM optimization problem conditional on $\{x_m^f,\ m \in \mathcal{M}\}$; and (ii) record the resulting dual variable ("shadow price") solution values $\lambda_\ell^{1,f}(t)$ and $\lambda_\ell^{2,f}(t)$ corresponding to the lower and upper line power transmission constraints in (8) for each line $\ell \in \mathcal{L}$ and each hour $t \in \mathcal{T}$.

C. Line Congestion Risk Indices

Transmission lines that are frequently congested are generally referred to as *critical* lines. In the SC DAM optimization formulation developed in Section IV, the lower and upper dual variables for (8) indicate the congestion status of the transmission lines.

Given the dual variable solution values in Section V-B, a *line congestion risk index* is constructed for each transmission line $\ell \in \mathcal{L}$ as follows:

$$w_\ell = \frac{\sum\limits_{f \in \mathcal{F}} \sum\limits_{t \in \mathcal{T}} \max\left\{|\lambda_\ell^{1,f}(t)|, |\lambda_\ell^{2,f}(t)|\right\} \widehat{\text{Prob}}(f)}{|\mathcal{T}|} . \quad (23)$$

By construction, the larger the value of w_ℓ, the more likely it is that line ℓ will experience congestion, given the set $\mathcal{F}$ of net load forecasts f with associated probabilities $\widehat{\text{Prob}}(f)$.

D. Shift Factor Index

Let $\text{SF}_{\ell,i} = \text{SF}(\ell, 1\text{MW}, i, \text{ref})$ denote the shift factor that measures the change in power flow on line ℓ when 1MW of power is injected at bus i and withdrawn at the designated reference bus ref; cf. footnote 9. Given any two buses i and j, we construct a weighted average of shift factor differences for these buses as follows:

$$\text{SFWA}_{ij} = \frac{\sum\limits_{\ell \in \mathcal{L}} w_\ell |\text{SF}_{\ell,i} - \text{SF}_{\ell,j}|}{|\mathcal{L}|} , \quad (24)$$

where the weights w_ℓ in (24) are the line congestion risk indices given by (23). Finally, the matrix whose components are given by $\text{SFWA}_{i,j}$ is denoted by SFWA.

E. Reserve Zone Specification

The well-known hierarchical clustering method developed by [22] proceeds as follows. Consider a finite set $\mathcal{N}$ consisting of $N \geq 2$ elements for which the dissimilarity between any two elements i and j in $\mathcal{N}$ is measured by some designated dissimilarity metric $d(i,j)$. The dissimilarity between any two disjoint subsets of $\mathcal{N}$ can then be measured in a variety of ways: e.g., via *average dissimilarity* calculated as the average dissimilarity between any element of one subset and any element of the other subset.

Start with a partition $P(N)$ of $\mathcal{N}$ into N disjoint subsets, each subset containing a single element. Find a pair of subsets in $P(N)$ whose dissimilarity to each other is at least as small as between any other two subsets in $P(N)$ and merge these two subsets; this results in a partition $P(N-1)$ of $\mathcal{N}$ into $N-1$ disjoint subsets. Repeat this process until one obtains $P(1)$, a "partition" of $\mathcal{N}$ into one subset $\mathcal{N}$.

At each stage of this clustering process, by construction, the dissimilarity between the two merged subsets is non-decreasing. If the goal is to obtain a partitioning of $\mathcal{N}$ into subsets that display internal element similarity and between-subset dissimilarity, a natural place to stop the process is at a point where the dissimilarity between the next two subsets to be merged exhibits a sharp increase.

In the current study, this hierarchical clustering method is applied to the set $\mathcal{B}$ consisting of all grid buses in order to partition $\mathcal{B}$ into reserve zones. The dissimilarity between any two buses i and j in $\mathcal{B}$ is measured by $\text{SFWA}_{i,j}$, and the dissimilarity between any two disjoint bus subsets is measured by the average dissimilarity of their bus elements. A sharp increase in subset dissimilarity is used to determine the point at which the clustering process is halted.

VI. PERFORMANCE TEST PRELIMINARIES

A. Overview

Five-bus and thirty-bus SC DAM test cases are used in Sections VII and VIII to evaluate the performance of our ISO-managed SC DAM optimization formulation with dynamically adjusted reserve zones over three successive days. Two different reserve zone treatments are considered for each test case:

- Z-1: Single system-wide reserve zone;
- Z-2: Reserve zones daily updated via our proposed new method presented in Section V.

A zone treatment Z can result in two types of error that affect SC DAM performance: 1) the ISO clears too many SCs; or 2) the ISO clears too few SCs. Given a type-1) error, the ISO pays too much offer cost. Given a type-2) error, the ISO might have to resort to relatively expensive imbalance adjustments to service next-day net load, such as load curtailments or purchases of additional power from expensive peaker units.

A type-1) error could arise because Z is overly optimistic with regard to actual next-day opportunities to dispatch generation from a variety of smaller generators with relatively cheap performance costs. During next-day operations, unanticipated transmission congestion could prevent some of these smaller generators from actually being used to service net load.

A type-2) error could arise because Z is overly optimistic with regard to actual next-day opportunities to dispatch generation from a large generator with relatively cheap performance costs. During next-day operations, unanticipated transmission congestion could prevent some or all of this large generator's capacity from being used to service net load.

The key question addressed in Sections VII and VIII is whether zone treatment Z.2 is able to reduce the occurrence of type 1) and/or type 2) errors relative to the benchmark zone treatment Z.1, resulting in significant reductions in total cost.

B. Computational Requirements

Table I provides a rough measure of the computational time required to solve our 5-bus and 30-bus SC DAM test cases. These requirements indicate that a personal computer could have been used to run these test-case simulations.

However, we used a High Performance Computer (HPC) at ISU to run our simulations in order to take advantage of previously installed optimization software. The individual blades of the HPC consist of two 2.6 GHz 8-Core Intel E5-2640 v3 processors and 128GB of RAM. Pyomo 5.3.0 was used to formulate the SC DAM optimization problem, and CPLEX Python API 12.6 was employed as the MILP solver.

TABLE I
COMPUTATIONAL REQUIREMENTS FOR THE SC DAM TEST CASES

Case	#Integer Var.	#Continuous Var.	#Constraints
5-Bus	125	964	1,602
30-Bus	150	3,676	4,888

C. Construction of Net Load Scenarios and Forecasts

As seen in Section IV, our day-D SC DAM optimization is conditioned on net load forecasts for day D+1. Net load is load minus non-dispatchable generation. For concreteness, it is assumed that non-dispatchable generation consists entirely of wind power.

As will be seen in Sections VII and VIII, 5-bus and 30-bus test cases are used to evaluate the performance of our SC DAM optimization over three successive days, hereafter denoted by (D_0, D_1, D_2). Thus, ISO *forecasts* for *next-day* net loads need to be constructed for days (D_1, D_2, D_3).

Moreover, for performance measurement purposes, sets $\mathcal{S}$ representing all possible net load scenarios that could *actually* occur during days (D_1, D_2, D_3) also need to be constructed. Each scenario s in $\mathcal{S}$ takes the form

$$s \equiv \{NL_b^s(t, D) \mid b \in \mathcal{B}, t \in \mathcal{T}, D \in \mathcal{D}\}, \quad (25)$$

where $NL_b^s(t, D)$ denotes net load at bus b for hour t of day D, and $\mathcal{D} = \{D_1, D_2, D_3\}$.

This section summarizes the way in which we used ERCOT hourly load and wind generation data to construct these net load scenarios and forecasts. Detailed descriptions of these constructions are provided in Appendix A.

Consider, first, the 5-bus SC DAM test cases. Hourly load and wind generation data were obtained for three successive months (June-August) in three successive years (2015-2017) for the ERCOT energy region [23]. These data were used to construct a set $\mathcal{S}^{5\text{Bus}}$ consisting of 90 three-day net load scenarios s taking form (25), with the elements of $\mathcal{B}$ given by the 5 buses for the 5-bus test case grid. Each $s \in \mathcal{S}^{5\text{Bus}}$ was assigned Prob(s) = 1/90.

Next consider the 30-bus SC DAM test cases. Hourly load and wind generation data were obtained for five successive months (April-August) in three successive years (2015-2017) for the ERCOT energy region [23]. These data were used to construct a set $\mathcal{S}^{30\text{Bus}}$ consisting of 150 three-day net load scenarios s taking form (25), with the elements of $\mathcal{B}$ given by the 30 buses for the 30-bus test case grid. Each $s \in \mathcal{S}^{30\text{Bus}}$ was assigned Prob(s) = 1/150.

Let $\mathcal{S}$ denote the net load scenario set for either the 5-bus or 30-bus SC DAM test cases. Suppose the current simulated day is $D_j \in \{D_0, D_1, D_2\}$. For each reserve zone treatment for this test case, the ISO's net load forecast $\widehat{NL}_b(t, D_{j+1})$ for net load at bus b during hour t of day D_{j+1} is specified to be the unconditional expectation for this next-day net load. More precisely, for each $b \in \mathcal{B}$ and $t \in \mathcal{T}$:

$$\widehat{NL}_b(t, D_{j+1}) = \sum_{s \in \mathcal{S}} NL_b^s(t, D_{j+1})\text{Prob}(s). \quad (26)$$

To give a sense of the form of these data-based net load scenarios, and the ISO's corresponding net load forecast, Fig. 5 depicts these constructions in aggregated form for the 30-bus test cases.
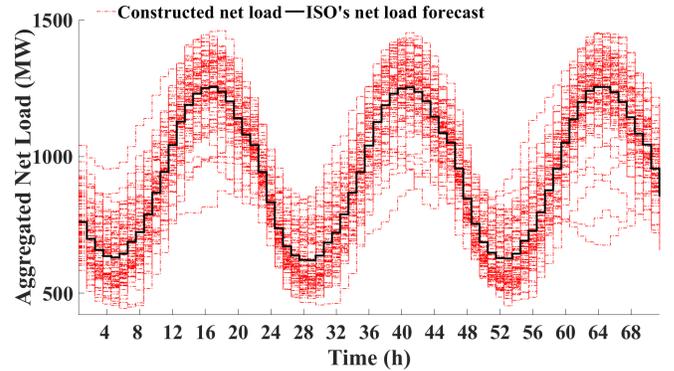

Fig. 5. The 150 possible net load scenarios, together with the ISO's corresponding net load forecast, for the 30-bus SC DAM test cases. These constructions are aggregated across buses for visualization purposes. Each constuction covers three successive days (72 hours).

Finally, for each simulated day D_j, $j = 0, 1, 2$, the set $\mathcal{F}_{j+1}$ of possible net load forecasts for day D_{j+1} used in Step 1 of our reserve zone updating procedure presented in Section V is constructed as follows. For each $s \in \mathcal{S}$, define

$$f_{j+1}^s = \{NL_b^s(t, D_{j+1}) \mid b \in \mathcal{B}, t \in \mathcal{T}\}, \quad (27)$$

with $\widehat{\text{Prob}}(f_{j+1}^s) = \text{Prob}(s)$. Then

$$\mathcal{F}_{j+1} = \{f_{j+1}^s \mid s \in \mathcal{S}\}. \quad (28)$$

D. Construction of Performance Metrics

As seen in Section IV, the total cost objective function (3) for the SC DAM optimization consists of three cost components: (i) offer costs; (ii) expected ex post performance costs; and (iii) expected ex post imbalance costs. The costs (ii) and (iii) are "expected" costs because the SC DAM optimization is conditioned on ISO net load forecasts for the following day.

The 5-bus and 30-bus SC DAM test cases report the performance of the SC DAM optimization in terms of three performance metrics measuring these three distinct types of costs. Specifically, for each zone treatment Z and each simu-

lated day $D_j \in \{D_0, D_1, D_2\}$, the following three performance metrics are calculated for the day-D_j SC DAM optimization:

- **OC(Z,D_j):** Offer cost, i.e., the payment of offer prices to sellers of cleared SCs on day D_j in return for ensuring the availability of services on day D_{j+1};
- **$E^{xp}[PC(Z,D_j)]$:** Expected ex-post performance cost, i.e., the expected compensation to be paid ex post to sellers of cleared SCs for actual performance of services on day D_{j+1}, where the expectation is taken with respect to the set $\mathcal{S}$ of all possible net load scenarios s for day D_{j+1};
- **$E^{xp}[IC(Z,D_j)]$:** Expected ex-post imbalance cost, i.e., the expected costs arising on day D_{j+1} from imbalance adjustments (e.g., load curtailments), where the expectation is taken with respect to the set $\mathcal{S}$ of all possible net load scenarios s for day D_{j+1}.

The precise calculation of these three performance metrics is explained in Appendix B.

Given these three performance metrics, the key factor determining the relative performance of a day-D_j SC DAM optimization under different zone treatments Z is the form of the SC-clearing indicator solutions. More precisely, let the solution values for the cleared contract indicators x_m in the day-D_j SC DAM optimization under a zone-updating method Z be denoted by

$$\mathcal{X}(Z,D_j) = \{x_m(Z,D_j) \mid m \in \mathcal{M}\} . \tag{29}$$

Then a necessary condition for at least one of the three performance metrics to be different under two different zone treatments Z1 and Z2 is that $\mathcal{X}(Z1,D_j) \neq \mathcal{X}(Z2,D_j)$. This follows because, as explained in Appendix B, the expected ex-post performance and imbalance costs for real-time operations on day D_{j+1} are calculated without imposition of reserve constraints.

VII. FIVE-BUS SC DAM PERFORMANCE TESTS

A. Five-Bus System Configuration

The five-bus system used to implement all of our 5-bus SC DAM test cases is adapted from [24]. As depicted in Fig. 6, the grid consists of five buses B1-B5 and six transmission lines L1-L6. The participants include: five dispatchable thermal generators G1-G5 located at buses B1, B3, B4, and B5; one non-dispatchable wind farm located at bus B3; and three LSEs servicing load at buses B2, B3, and B4. The designated reference bus is B4.

The time step for the SC DAM optimization was set at $\Delta t = $ 1h, and the planning horizon $\mathcal{T}$ was specified to be 24 hours. The ISO's estimate $\widehat{d}$ for the maximum down/up deviation of net load from its LSE forecasted value was commonly set at the decimal percentage 0.05. The imbalance penalties for excess and deficit power were set at $\Lambda_1 = \$1000/\text{MWh}$ and $\Lambda_2 = \$1000/\text{MWh}$. The positive base power S_o was set equal to 100 MVA. Finally, the physical attributes of the six transmission lines were specified as in Table II.

The SCs submitted into the SC DAM by G1-G5 all take form (1); hence, swing (flexibility) is offered in power and ramp-rate levels. These SCs are shown in Table III.
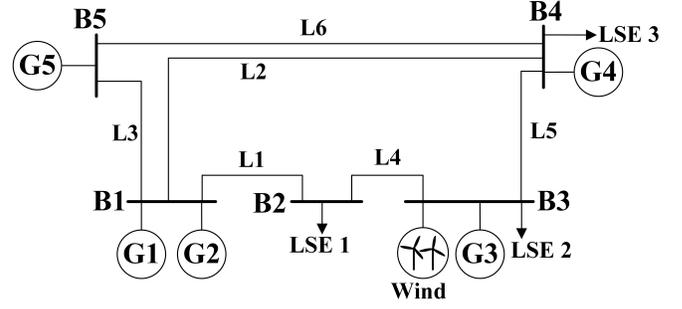

Fig. 6. Five-bus test system used for SC DAM performance testing.

TABLE II
TRANSMISSION LINE DATA FOR THE 5-BUS SC DAM TEST CASES

Line	From Bus	To Bus	X(p.u.)	Limit(MW)
L1	B1	B2	0.0281	450
L2	B1	B4	0.0304	300
L3	B1	B5	0.0064	250
L4	B2	B3	0.0108	200
L5	B3	B4	0.0297	150
L6	B4	B5	0.0297	240

B. Five-Bus SC DAM Test Case Outcomes

Performance outcomes for our 5-bus SC DAM test cases are reported in Table IV for three successive simulated days (D_0, D_1, D_2) under two different reserve zone treatments: a single system-wide regulation reserve zone ("Single"); and our method proposed in Section V for the daily updating of regulation reserve zones ("Proposed"). For each zone treatment Z, three different performance metrics are reported: offer cost OC(Z,D_j); expected ex post performance cost $E^{xp}[PC(Z,D_j)]$; and expected ex post imbalance cost $E^{xp}[IC(Z,D_j)]$.[10]

The first observation is that the two tested zone treatments Z yield different solution values for the contract clearing indicators $\mathcal{X}(Z,D_j)$ for each day D_j, implying that different sets of SCs are cleared on each day D_j. Consequently, it is not surprising to see that performance metric outcomes also differ on each day D_j.

A second observation is that the "Single" zone treatment results in lower offer cost than the "Proposed" zone treatment on each day D_j. However, this is not the case for the remaining two cost components. The combined expected ex post performance and imbalance costs for "Single" are substantially higher than those for "Proposed" on each day D_j. This finding reflects the lack of attention paid by "Single" to possible reserve deliverability problems on day D_{j+1} due to transmission congestion.

A third observation is that the "Proposed" zone treatment exhibits lower expected ex post imbalance cost on each successive day. Indeed, by day D_2 this cost has dropped to zero; and expected ex post performance cost has also obtained

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[10]See Section VI and Appendix B for detailed explanations of these performance metrics.

TABLE III
5-BUS SC DAM TEST CASES: SWING CONTRACTS (SCS) SUBMITTED BY THE FIVE THERMAL GENERATORS OVER THREE SUCCESSIVE DAYS

Day D_j	Thermal Gen	Service Period $[t_s, t_e]$	Power Range $[P^{min}, P^{max}]$ (MW)	Ramp Rate Range $[-R^D, R^U]$ (MW/h)	Offer Price π^o ($)	Performance Price ϕ ($/MWh)
	G1	$[1, 24]$	$[10, 380]$	$[-150, 150]$	1400	10
	G2	$[4, 22]$	$[10, 325]$	$[-150, 150]$	1200	12
D_0	G3	$[1, 24]$	$[50, 385]$	$[-240, 240]$	1150	11
	G4	$[4, 22]$	$[20, 100]$	$[-50, 50]$	1100	18
	G5	$[1, 24]$	$[40, 600]$	$[-320, 320]$	1800	30
	G1	$[3, 24]$	$[10, 340]$	$[-150, 150]$	1200	10
	G2	$[1, 24]$	$[10, 160]$	$[-80, 80]$	1328	12
D_1	G3	$[1, 24]$	$[50, 320]$	$[-240, 240]$	1550	20
	G4	$[1, 22]$	$[20, 400]$	$[-200, 200]$	1600	18
	G5	$[1, 24]$	$[40, 600]$	$[-320, 320]$	1780	25
	G1	$[1, 24]$	$[10, 380]$	$[-150, 150]$	1200	10
	G2	$[3, 22]$	$[10, 325]$	$[-150, 150]$	1350	13
D_2	G3	$[1, 24]$	$[50, 385]$	$[-240, 240]$	1000	10
	G4	$[3, 24]$	$[20, 100]$	$[-50, 50]$	1100	15
	G5	$[1, 24]$	$[40, 600]$	$[-320, 320]$	1800	28

TABLE IV
FIVE-BUS SC DAM PERFORMANCE OVER THREE SUCCESSIVE DAYS FOR TWO DIFFERENT RESERVE ZONE TREATMENTS

Day D_j	Treatment	Reserve Zones z	$\mathcal{X}(Z, D_j)$ $[x_{G1}, x_{G2}, x_{G3}, x_{G4}, x_{G5}]$	OC(Z, D_j)	E^{xp}[PC(Z, D_j)]	E^{xp}[IC(Z, D_j)]
D_0	Proposed	$z1$: Bus 3 $z2$: Bus 1 2 4 5	$[1, 1, 1, 0, 1]$	\$5,550	\$240,101.98	\$1,341.57
	Single Zone	$z1$: Bus 1-5	$[1, 1, 1, 1, 0]$	\$4,580	\$221,434.26	\$93,221.92
D_1	Proposed	$z1$: Bus 3 $z2$: Bus 1 2 4 5	$[1, 1, 1, 1, 1]$	\$6,750	\$296,338.67	\$928.84
	Single Zone	$z1$: Bus 1-5	$[1, 1, 1, 1, 0]$	\$5,730	\$288,859.21	\$71,695.40
D_2	Proposed	$z1$: Bus 3 $z2$: Bus 1 2 4 5	$[1, 1, 1, 1, 1]$	\$6,450	\$236,409.59	\$0.00
	Single Zone	$z1$: Bus 1-5	$[1, 1, 1, 0, 1]$	\$5,350	\$238,877.33	\$2,466.25

its lowest value.

A fourth observation is that the cost differences observed from one day to the next under both zone treatments are entirely due to net load variations from one day to the next. Although the "Proposed" zone treatment permits the daily updating of reserve zones based on forecasted grid congestion conditions, the original zone specification on day D_0 remained "optimal" for all three simulated days.

A 5-bus grid is relatively small, so it is perhaps unsurprising that the "Proposed" zone treatment did not result in any updating of zones over the three simulated days. As will next be reported in Section VIII, dramatically different results were observed for the 30-bus SC DAM test cases.

VIII. THIRTY-BUS SC DAM PERFORMANCE TESTS

A. Thirty-Bus System Configuration

The 30-bus system used to implement all 30-bus SC DAM test cases reported in this study is adapted from [25]. As depicted in Fig. 7, the grid consists of 30 buses B1-B30 and 41 transmission lines L1-L41.
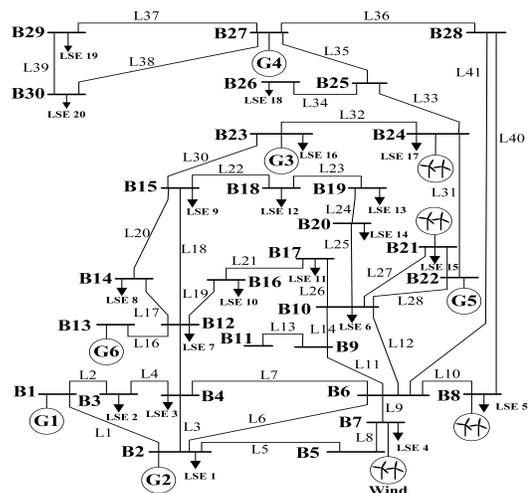

Fig. 7. Thirty-bus test system used for SC DAM performance testing.

The participants in the 30-bus system include: 6 dispatchable thermal generators G1-G6 located at buses B1, B2, B23,

TABLE V
30-BUS SC DAM TEST CASES: SWING CONTRACTS (SCs) SUBMITTED BY THE SIX THERMAL GENERATORS OVER THREE SUCCESSIVE DAYS

Day D_j	Thermal Gen	Service Period $[t_s, t_e]$	Power Range $[P^{\min}, P^{\max}]$ (MW)	Ramp Rate Range $[-R^D, R^U]$ (MW/h)	Offer Price π^o ($)	Performance Price ϕ ($/MWh)
	G1	$[1, 24]$	$[30, 120]$	$[-80, 80]$	1500	25
	G2	$[1, 24]$	$[20, 100]$	$[-80, 80]$	1700	18
D_0	G3	$[1, 24]$	$[15, 50]$	$[-30, 30]$	1950	25
	G4	$[1, 24]$	$[10, 50]$	$[-30, 30]$	1800	25
	G5	$[1, 22]$	$[10, 40]$	$[-20, 20]$	2000	24
	G6	$[1, 22]$	$[10, 40]$	$[-30, 30]$	1800	28
	G1	$[1, 24]$	$[30, 120]$	$[-80, 80]$	1500	12
	G2	$[2, 24]$	$[20, 120]$	$[-80, 80]$	1800	16
D_1	G3	$[1, 24]$	$[15, 50]$	$[-30, 30]$	1800	18
	G4	$[1, 24]$	$[10, 70]$	$[-30, 30]$	2500	35
	G5	$[2, 23]$	$[10, 40]$	$[-20, 20]$	1600	15
	G6	$[2, 24]$	$[10, 40]$	$[-30, 30]$	1500	18
	G1	$[3, 24]$	$[30, 120]$	$[-80, 80]$	1500	15
	G2	$[1, 24]$	$[20, 120]$	$[-80, 80]$	1900	18
D_2	G3	$[1, 24]$	$[15, 50]$	$[-30, 30]$	1760	14
	G4	$[1, 24]$	$[10, 70]$	$[-30, 30]$	1200	25
	G5	$[3, 22]$	$[10, 40]$	$[-20, 20]$	1600	16
	G6	$[3, 24]$	$[10, 40]$	$[-30, 30]$	1450	17

B27, B22, B13; 4 non-dispatchable wind farms located at buses B7, B8, B21, B24; and 20 LSEs servicing load at buses B2, B3, B4, B7, B6, B10, B12, B14, B15, B16, B17, B18, B19, B20, B21, B23, B24, B26, B29 and B30. The designated reference bus is B1.

As for the 5-bus test cases, the time step for the SC DAM optimization was set at $\Delta t = 1$h, and the planning horizon $\mathcal{T}$ was specified to be 24 hours. The ISO's estimate $\widehat{d}$ for the maximum down/up deviation of net load from its LSE forecasted value was commonly set at the decimal percentage 0.05. The imbalance penalties for excess and deficit power were set at $\Lambda_1 = \$1000$/MWh and $\Lambda_2 = \$1000$/MWh.

The SCs submitted into the 30-bus SC DAM by G1-G6 all take form (1), meaning that swing (flexibility) is offered in power and ramp levels. These SCs are shown in Table V.

B. Thirty-Bus SC DAM Test Case Outcomes

Similarly to what was done in Section VII-B for our 5-bus test cases, performance outcomes are reported in Table VI for our 30-bus SC DAM test cases for three successive simulated days (D_0, D_1, D_2) under the two reserve zone treatments "Single" and "Proposed." For each zone treatment Z, three different performance metrics are reported: offer cost OC(Z,D_j); expected ex post performance cost E^{xp}[PC(Z,D_j)]; and expected ex post imbalance cost E^{xp}[IC(Z,D_j)].

As for our 5-bus test cases, each zone treatment Z results in a different set of cleared SCs as well as different resulting values for the three performance metrics on each day D_j. Once again, the "Single" zone treatment is observed to result in lower offer cost but substantially higher expected ex post performance and imbalance costs than the "Proposed" zone treatment on each day D_j. Indeed, "Single" results in higher

expected ex post performance cost *and* higher expected ex post imbalance cost than "Proposed" on each day D_j.

However, in contrast to the 5-bus test cases, the performance outcomes for the 30-bus SC DAM test cases reveal that a substantial amount of zone updating now takes place from one day to the next under the "Proposed" zone treatment.

IX. CONCLUSION

This paper proposes a new formulation for a swing-contract day-ahead market (SC DAM) with regulation reserve zones. Optimal contract clearing for this SC DAM is formulated as a mixed integer linear programming (MILP) problem and solved using a standard MILP solver.

In addition, a method is proposed for the daily updating of the SD DAM's reserve zones based on a newly developed line congestion risk index. Performance studies using 5-bus and 30-bus SC DAM test cases demonstrate the practicality and effectiveness of this new dynamic reserve method.

Future studies will explore additional extensions of the SC DAM to handle dynamic updating of reserve zones for contingency as well as regulation reserves. In addition, the SC DAM optimization formulation will be generalized to allow SC portfolio offers permitting flexible provision of a wider range of services, such as storage and volt/VAR support.

APPENDIX A
NET LOAD SCENARIOS: TECHNICAL DETAILS

For use in each 5-bus SC DAM test case, we constructed a set $\mathcal{S}^{5\text{Bus}}$ of 90 net load scenarios s as follows. Hourly load and wind generation data were obtained for three successive months (June-August) in three successive years (2015-2017) for the ERCOT energy region [23]. Using the first 30 days of

TABLE VI
THIRTY-BUS SC DAM PERFORMANCE OVER THREE SUCCESSIVE DAYS FOR TWO DIFFERENT RESERVE ZONE TREATMENTS

Day D_j	Treatment	Reserve Zones z	$\mathcal{X}(Z,D_j)$ $[x_{G1}, x_{G2}, x_{G3}, x_{G4}, x_{G5}, x_{G6}]$	$OC(Z,D_j)$	$E^{xp}[PC(Z,D_j)]$	$E^{xp}[IC(Z,D_j)]$
D_0	Proposed	$z1$: Bus 23 $z2$: Bus 27 29 30 $z3$: Bus 1-22 24 25 26 28	$[1, 1, 1, 1, 1, 1]$	$10,750	$100,555.65	$194.22
	Single Zone	$z1$: Bus 1-30	$[1, 1, 1, 1, 0, 1]$	$8,750	$106,420.12	$5,371.73
D_1	Proposed	$z1$: Bus 23 $z2$: Bus 21 22 24-27 29 30 $z3$: Bus 1-20 28	$[1, 1, 1, 1, 1, 1]$	$10,700	$98,012.73	$10,359.74
	Single Zone	$z1$: Bus 1-30	$[1, 1, 1, 1, 0, 1]$	$9,100	$99,996.96	$13,990.73
D_2	Proposed	$z1$: Bus 23 24 25 26 $z2$: Bus 27 29 30 $z3$: Bus 1-22 28	$[1, 1, 1, 1, 1, 1]$	$9,410	$104,494.04	$10,597.97
	Single Zone	$z1$: Bus 1-30	$[1, 1, 1, 1, 0, 1]$	$7,810	$105,077.11	$13,282.30

data for *each* of the three months in *each* of the three years, ten 3-day scenarios were separately constructed for load and for wind generation, resulting in $10 \times 3 \times 3 = 90$ load and wind generation scenarios.

The hourly load and wind generation levels in these 90 scenarios were next distributed across the five buses of the 5-bus grid. Specifically, hourly load was distributed across buses B2, B3, and B4 as 40%, 30%, and 30% of total hourly load, respectively. Hourly wind generation was then subtracted from hourly load at bus B3. This process resulted in 90 net load scenarios taking form (25). Each of these 90 net load scenarios s was assigned Prob(s) = 1/90.

Similarly, for use in each 30-bus SC DAM test case, we constructed a set $\mathcal{S}^{30Bus}$ of 150 net load scenarios s as follows. Hourly load and wind generation data were obtained for five successive months (April-August) in three successive years (2015-2017) for the ERCOT energy region [23]. Using the first 30 days of data for *each* of the five months in *each* of the three years, ten 3-day net load scenarios were separately constructed for load and wind generation, resulting in $10 \times 5 \times 3$ = 150 load and wind generation scenarios.

The hourly load and wind generation levels in these 150 scenarios were next distributed across the thirty buses of the 30-bus grid. Specifically, hourly load was distributed across buses B2, B3, B4, B7, B6, B10, B12, B14, B15, B16, B17, B18, B19, B20, B21, B23, B24, B26, B29 and B30 as 11%, 1%, 4%, 12%, 16%, 3%, 6%, 3%, 4%, 2%, 5%, 2%, 5%, 1%, 9%, 2%, 5%, 2%, 1%, and 6% of total hourly load, respectively. Hourly wind generation was distributed equally (25% portions) across the four buses B7, B8, B21 and B24. This hourly wind generation was then subtracted from hourly load at these buses. This process resulted in 150 net load scenarios taking form (25). Each of these 150 net load scenarios s was assigned Prob(s) = 1/150.

APPENDIX B
PERFORMANCE METRICS: TECHNICAL DETAILS

As noted in Section VI-D, for each zone treatment Z, and for each simulated day $D_j \in \{D_0, D_1, D_2\}$, the following three performance metrics are calculated for the day-D_j SC DAM: Offer cost $OC(Z,D_j)$; expected ex-post performance cost $E^{xp}[PC(Z,D_j)]$; and expected ex-post imbalance cost $E^{xp}[IC(Z,D_j)]$. The precise calculation of these three performance metrics will now be explained.

Let a particular SC DAM test case be given, and let $\mathcal{S}$ be a finite set consisting of all possible 3-day net load scenarios s that could be realized for days $\mathcal{D} = \{D_1, D_2, D_3\}$. Let the scenarios in $\mathcal{S}$ be enumerated as $s_1, \ldots, s_N$ for some $N \geq 1$, and let Prob(s) = 1/N for each $s \in \mathcal{S}$. Let day D_j be given, j = 0, 1, or 2, and let an ISO net load forecast for day D_{j+1} be constructed as in (26), conditional on $\mathcal{S}$. Finally, let a particular zone treatment Z also be given.

First, solve the day-D_j SC DAM optimization in Section IV, given the ISO net load forecast for day D_{j+1}. Let the solution values for the cleared contract indicators x_m be denoted by

$$\mathcal{X}(Z,D_j) = \{x_m(Z,D_j) \mid m \in \mathcal{M}\} . \tag{30}$$

The offer cost $OC(Z,D_j)$ is then calculated to be

$$OC(Z,D_j) = \sum_{m \in \mathcal{M}} \pi_m^o(Z,D_j) x_m(Z,D_j) , \tag{31}$$

where $\pi_m^o(Z,D_j)$ denotes the offer price requested by seller m for the swing contract he submitted to the day-D_j SC DAM.

Next, designate scenario $s_1 \in \mathcal{S}$ to be the *simulated true* net load scenario for days (D_1, D_2, D_3), i.e., the net load scenario representing the net load that was actually realized over these three days. Solve an "ex post" (real-time) form of the day-D_j SC DAM optimization, i.e., a day-D_j SC DAM optimization with the following additional restrictions imposed: (i) the cleared contract indicators x_m are set equal to the values in 30; (ii) all reserve zones and constraints are removed; and (iii) the ISO's net load forecast for day D_{j+1} is replaced by the simulated-true net load for day D_{j+1} as determined by s_1.

Calculate the performance cost PC(Z,D$_j$,s_1) and imbalance cost IC(Z,D$_j$,s_1) that result from the solution of this ex-post optimization.

Repeat the above calculations for each of the remaining scenarios $s_2,\ldots,s_N \in \mathcal{S}$. After this is done, calculate the expected ex-post performance cost and the expected ex-post imbalance cost as follows:

$$E^{\mathrm{xp}}[\mathrm{PC}(Z,D_j)] = \sum_{n=1}^{N}[\mathrm{PC}(Z,D_j,s_n)]/N \ ; \tag{32}$$

$$E^{\mathrm{xp}}[\mathrm{IC}(Z,D_j)] = \sum_{n=1}^{N}[\mathrm{IC}(Z,D_j,s_n)]/N \ . \tag{33}$$

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