7-2-2017

Working Paper Number 17020

A Swing-Contract Market Design for Flexible Service Provision in Electric Power Systems

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Original Release Date: February 1, 2017
Latest Revision: July 2, 2017

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Abstract

The need for flexible service provision in electric power systems has dramatically increased due to the growing penetration of variable energy resources, as has the need to ensure fair access and compensation for this provision. A swing contract (SC) facilitates flexible service provision because it permits multiple service attributes to be offered together in bundled form with each attribute expressed as a range of possible values rather than as a single point value. This paper discusses a new SC Market Design for electric power systems that permits SCs to be offered by any dispatchable resource. An analytical optimization formulation is developed for the clearing of an SC day-ahead market that can be implemented using any standard mixed integer linear programming (MILP) solver. The practical feasibility of the optimization formulation is demonstrated by means of a numerical example.

Keywords

Flexible service provision, swing contract, day-ahead electric power market, optimal market clearing

Disciplines

Economic Theory | Electrical and Computer Engineering | Industrial Organization | Oil, Gas, and Energy | Power and Energy

A Swing-Contract Market Design for Flexible Service Provision in Electric Power Systems

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Abstract The need for flexible service provision in electric power systems has dramatically increased due to the growing penetration of variable energy resources, as has the need to ensure fair access and compensation for this provision. A swing contract facilitates flexible service provision with appropriate compensation because it permits multiple services to be offered together in bundled form with each service expressed as a range of possible values rather than as a single point value. This paper discusses a new swing-contract market design for electric power systems that permits swing contracts to be offered by any dispatchable resource. An analytical optimization formulation is developed for the clearing of a swing-contract day-ahead market that can be implemented using any standard mixed integer linear programming solver. The practical feasibility of the optimization formulation is demonstrated by means of a numerical example.

1 Introduction

The increased penetration of variable energy resources in electric power markets has increased the volatility of *net load* (i.e., load minus non-dispatchable generation) as well as the frequency of strong ramp events. *Variable energy resources (VERs)* are renewable energy resources, such as wind and solar power, whose generation cannot be closely controlled to match changes in load or to meet other system requirements.

Latest Revision: 2 July 2017
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In consequence, flexibility in ancillary service provision has become increasingly important to maintain the reliability and efficiency of power system operations. This has encouraged power system operators to introduce new products and market processes designed to permit more flexibility in ancillary service provision, thus enhancing net load following capability [13].

Nevertheless, three important issues arising from increased VER penetration still need to be resolved. First, power and reserve products are variously defined and compensated across the different energy regions; see, e.g., [11]. This lack of standardization makes it difficult to compare and evaluate the reliability, efficiency,and fairness of system operations across these regions.

Second, product definitions are specified in broad rigid terms (e.g., capacity, energy, ramp-rate, regulation, non-spinning reserve). These rigid categorizations do not permit resources to be further differentiated and compensated on the basis of additional valuable flexibility in service provision, such as an ability to ramp up and down between minimum and maximum values over very short time intervals.

Moreover, the 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 "ramp-rate" be properly valued apart from a consideration of other power path attributes, such as start time, duration, and power range?

Third, attempts to accommodate new products have led to the introduction of *out-of-market (OOM)* compensation processes. In 2011 the U.S. *Federal Energy Regulatory Commission (FERC)* issued Order 755 to address OOM payment problems for one particular product category in U.S. centrally-managed wholesale power markets: namely, regulation with different abilities to follow electronic dispatch signals with high accuracy [12]. However, given its limited scope, Order 755 does not fully eliminate the need in these markets to resort to OOM processes. As stressed in [4], the additional complexity resulting from OOM compensation processes provides increased opportunities for market participants to gain unfair profit advantages through strategic behaviors.

A group of researchers has been working to develop a new swing-contract market design for electric power systems that permits greater flexibility in service provision while at the same time addressing the above three issues [15, 22]. This work builds on important earlier work [2, 3, 8, 19] that stresses the relevance of options and two-part pricing contracts for electricity transactions.

The *swing contract (SC)* proposed in [15, 22] permits a resource with dispatchable power to offer into an electric power market a collection of available power paths with a wide range of specified services, such as start-location, start-time, power level, ramp rate, duration, and volt/VAr support. Each of these services can be offered as a range of values rather than as a point value, thus permitting greater flexibility in real-time implementation to meet both power and reserve needs. Moreover, permitting the resource to offer its services into the market in bundled form, as a collection of available power paths, helps to ensure that all of its valued services receive appropriate compensation.

Simple examples are used in [15, 22] to illustrate how the trading of SCs could be supported by a sequence of linked centrally-managed forward markets in a manner that permits efficient real-time balancing of net load subject to system and reserve-requirement constraints. In comparison with existing wholesale electric power market designs, the following key policy implications of this SC market design are highlighted.

- permits full market-based compensation for availability and performance
- facilitates a level playing field for market participation
- facilitates co-optimization of power and reserve markets
- supports forward-market trading of power and reserve
- permits service providers to offer flexible service availability
- provides system operators with real-time flexibility in service usage
- facilitates accurate load forecasting and following of dispatch signals
- permits resources to internally manage unit commitment and capacity constraints
- permits the robust-control management of uncertain net load
- eliminates the need for out-of-market payment adjustments
- reduces the complexity of market rules

Left unresolved in this previous conceptual work, however, is whether the determination of optimal market-clearing solutions for SCs can be reduced to a routine operation suitable for real-world application. The present study provides an affirmative answer to this question for a general SC day-ahead market design permitting swing contracts to be offered by any dispatchable resource.[1]

Section 2 presents and motivates an illustrative form of SC permitting the flexible provision of power and reserve services in electric power markets. The basic operational features of existing U.S. day-ahead and real-time market designs are outlined in Section 3. Section 4 discusses in broad terms a new market design for the support of SC trading, with a particular focus on a centrally-managed SC day-ahead market design that permits SCs to be offered by any dispatchable resource. Key distinctions between this SC day-ahead market design and existing U.S. day-ahead market designs are highlighted.

Section 5 then presents a new optimization formulation for the market clearing of SCs in the SC day-ahead market. This formulation constitutes a *mixed integer linear programming (MILP)* problem that can be solved by means of the same MILP solution software currently in use for standard security-constrained unit commitment optimization formulations [6, 14, 20, 24]. A numerical example is provided in Section 6 to demonstrate the practical feasibility of this new optimization formulation.

Concluding remarks are given in Section 7. A nomenclature table listing symbols and symbol definitions is provided in an appendix.

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[1] The present study is a substantial extension of an earlier preliminary study [17] by the authors appearing in an electronic conference proceedings.

2 An Illustrative Swing Contract in Firm Form

Four types of contracts are proposed in [15] to facilitate power and reserve trading: namely, firm contracts and option contracts taking either a fixed or swing form. A *firm contract (FC)* imposes specific obligations on the buyer and seller regarding how the buyer will procure services from the seller in accordance with contractually specified terms. In contrast, an *option contract (OC)* gives the buyer the right, but not the obligation, to procure services from the seller in accordance with contractually specified terms. The right can be activated by exercise of the OC at a contractually permitted exercise time, at which point the contractual terms of the OC become firm.

An FC or OC is a *fixed contract* if each of its offered services is expressed as a single value. An FC or OC is a *swing contract (SC)* if at least one of its offered services is expressed as a set of possible values, thus permitting some degree of flexibility in its implementation.

For concreteness, this study focuses on SCs in firm form that offer a particular spectrum of services expressed in time-domain terms.[2] The form of these SCs is as follows:

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

b = location where service delivery is to occur;

t_s = power delivery start time;

t_e = power delivery end time;

$\mathscr{P} = [P^{min}, P^{max}]$ = range of power levels p;

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

ϕ = Performance payment method for real-time services.

In (1), the location b would typically refer to a bus or node of a transmission grid. The times t_s and t_e denote specific calendar times expressed at the granularity of time periods of length Δt (e.g., 1 hour, 1 minute), with $t_s < t_e$. The power interval bounds $P^{min} \le P^{max}$ can represent pure power injections (if $0 \le P^{min}$), pure power withdrawals or absorptions (if $P^{max} \le 0$), or bi-directional power capabilities (if $P^{min} \le 0 \le P^{max}$). The down/up limits $-R^D$ and R^U for the ramp rates r (MW/Δt) are assumed to satisfy $-R^D \le 0 \le R^U$.

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 $\mathscr{P}$ and $\mathscr{R}$.

The performance payment method ϕ designates the mode of ex post compensation to be paid to the seller of the SC if this seller is called upon to provide actual services. This performance payment method can take a wide variety of forms.

[2] As stressed in [1], the services extracted from resources can alternatively be expressed in terms of their frequency bandwidth characteristics. The general concept of a swing contract does not depend on the exact manner in which services are characterized.

For example, ϕ could be a flat-rate price ($/MWh) to be applied to the total amount of energy (MWh) injected into the grid between t_s and t_e. Alternatively, ϕ could specify that the price ($/MWh) to be paid for power (MW) injected into the grid between t_s and t_e is contingent on the realization of some future event, such as the spot price of fuel between t_s and t_e. Also, ϕ might include a metric for the compensation of ramping, such as some form of "mileage" metric based on the length of any delivered down/up power path.[3] 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.[4]

To understand the obligations of the seller and buyer of an SC (1), should it be cleared, a numerical example might be helpful. Consider the following SC offered for sale in an ISO-managed day-ahead market by a market participant m in return for a requested *availability price* α = $100,[5] where Δt = 1 hour.

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

This SC implies that market participant m is offering to provide power at bus b from 8:00am to 10:00am on the following day. The power levels at which m is willing to be dispatched range from 10MW to 40MW, but the required down/up ramp rates r to achieve these power levels must satisfy -38MW/h $\leq r \leq$ 28MW/h. The performance payment method ϕ designates that m is to be paid the price ϕ=$35/MWh for each MWh of energy it delivers under this SC.

Suppose the ISO announces that this SC has been cleared. The seller m is then immediately entitled to receive its availability price α = $100. In return for this payment, m is "committed" for next-day operations in the following sense: m is obligated to ensure it will be available to perform the services promised in its cleared

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[3] For example, CAISO defines the *mileage* of a planned power path for a dispatchable resource to be the summation of the absolute changes in the successive *automated generation control (AGC)* set points that are used to communicate power dispatch instructions to this resource [5].

[4] Current penalties for failure to follow dispatch instructions are administratively determined. For example, CAISO uses a comparison of AGC set points to actual telemetry in order to judge the accuracy with which dispatch instructions have been followed. It then adjusts mileage payments when a resource fails to provide the power movements called for by dispatch instructions [5].

[5] The availability price α requested by the seller of an SC, i.e., the SC's offer price, is not considered to be part of the SC itself. In economics, physical commodities (e.g., apples) are considered separately from their offer prices. Similarly, standardized financial contracts (e.g., bonds) are treated as commodities that can be purchased in various market settings at possibly varying offer prices. In principle, this separation between a commodity/contract and its offer price facilitates price competition among commodity/contract sellers, thus increasing the likelihood that prices will be driven to efficient levels. See [21] for further discussion of this point.

SC if called upon to do so in next-day operations between 8:00am and 10:00am. In turn, the ISO is obligated to ensure that m is compensated fully, ex post, for any such service performance, in accordance with m's performance payment method ϕ.

Figure 1 depicts one possible power path that the ISO could dispatch in real-time operations, in accordance with the terms of this SC. The darker (green) area under this power path is the resulting energy (MWh) delivery, to be compensated ex post at the rate of \$35/MWh.

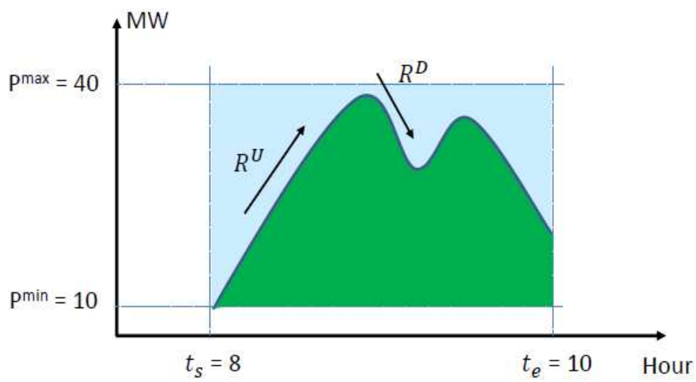

Fig. 1 A possible dispatched power path for the SC numerical example.

It is the responsibility of market participant m to ensure it is able to fulfill the terms of this offered SC. Two aspects must be considered: physical feasibility; and financial feasibility. With regard to physical feasibility, the power delivery start time t_s=8:00am must precede the power delivery end time t_e=10:00am, which is clearly the case. In addition, $[t_e - t_s] = 2h$ must be at least as great as m's minimum up time.[6]

With regard to financial feasibility, market participant m should make sure that all of its "avoidable costs" are covered. *Avoidable costs* are costs that can be avoided if an activity is not undertaken but that are incurred if it is undertaken.

Specifically, market participant m should make sure that its offered availability price α = \$100 covers all of the avoidable costs that m would have to pay in order to guarantee service availability. Also, m should make sure that its offered performance payment price ϕ = \$35/MWh is sufficient to cover all avoidable costs that m would have to pay if called upon to perform actual services. Examples of avoidable service availability costs include avoidable *unit commitment (UC)* costs, such as start-up/shut-down and no-load costs, as well as *lost-opportunity costs* arising from m's inability to receive revenues for its services in a next-best alternative use. Examples of avoidable service performance costs include avoidable costs for fuel and labor time.

[6] To help ensure the physical feasibility of offered SCs, an ISO might want to require all offered SCs to include in their performance payment methods some type of standardized failure-to-perform penalties. The severity of these penalties could be conditioned on the severity of past and current transgressions.

3 Existing U.S. Wholesale Power Market Designs

As depicted in Fig. 2, seven U.S. energy regions (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, SPP) encompassing over 60% of U.S. generation capacity currently have centrally-managed wholesale power markets.[7] Although specific market rules differ across these seven energy regions, particularly with regard to reserve procurement, their basic operational design can be roughly summarized as follows.

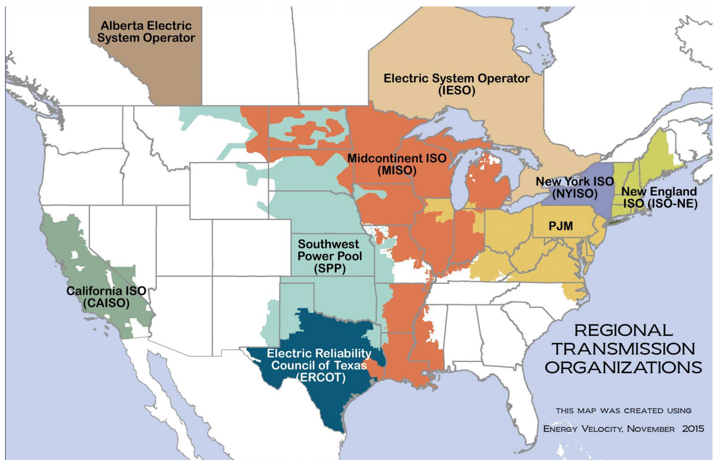

Fig. 2 Energy regions in North America that have ISO/RTO-managed wholesale power markets. Public domain source: [9].

Private *Generation Companies (GenCos)* sell bulk power to other private companies called *Load-Serving Entities (LSEs)*, who in turn resell this power to retail customers. The transactions between the GenCos and LSEs take place within a wholesale power market consisting of a *Day-Ahead Market (DAM)* and a *Real-Time Market (RTM)*, operating in parallel, which are centrally managed by an *Independent System Operator (ISO)* or *Regional Transmission Organization (RTO)*. Day-ahead generation schedules are determined in the DAM based on estimated next-day net loads. Any discrepancies that arise between DAM generation schedules for next-day operations and actual next-day needs for generation based on actual next-day net loads are handled in the RTM, which thus functions as a real-time balancing mechanism.[8]

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[7] For background readings on current U.S. wholesale power market operations pertinent for issues raised in the current study, see [7], [10], [16], [18], and [23].

[8] A GenCo is an entity that produces (supplies) power for an electric power grid. The term *load* is used in two senses: (i) to refer to an entity that consumes (absorbs) power from an electric power grid; and (ii) to refer to the power demands of such entities. The term *net load* is defined to be power demand net of non-dispatchable generation, such as wind or solar power. An LSE is an entity that secures power, transmission, and related services at the wholesale level in order to service

The physical power flows underlying these transactions take place by means of a high-voltage transmission grid that remains centrally managed by the ISO/RTO in order to ensure open access at reasonable access rates. Transmission grid congestion is managed in the DAM and RTM by *Locational Marginal Pricing (LMP)*.[9]

During the morning of each day d the GenCos and LSEs submit into the DAM a collection of power supply offers and power demand bids, respectively, for all 24 hours h of day d+1. Given these offers and bids, the ISO/RTO solves *Security-Constrained Unit Commitment (SCUC)* and *Security-Constrained Economic Dispatch (SCED)* optimization problems subject to standard system constraints[10] in order to determine the following planned outcomes at each transmission grid bus b for each hour h of day d+1: (i) GenCo unit commitments; (ii) scheduled dispatch levels (MW) for committed GenCos; and (iii) a locational marginal price $\pi^{DAM}(b,h,d)$ ($/MWh). A committed GenCo located at bus b is paid $\pi^{DAM}(b,h,d)$ for each MW of power it is scheduled to inject at b during hour h of day d+1, and an LSE must pay $\pi^{DAM}(b,h,d)$ for each MW of power its retail customers are scheduled to withdraw at bus b during hour h of day d+1.

The ISO/RTO undertakes an RTM SCED optimization at least once every five minutes during each day d. At the start of an RTM SCED on any day d, immediately prior to some operating period t, the ISO/RTO forecasts the net load for t. The ISO/RTO then conducts the RTM SCED optimization to resolve any discrepancies between the dispatch schedule determined in the day-(d-1) DAM for t on day d and the ISO/RTO's current forecasted net load for t on day d. Any dispatch adjustment and/or load curtailment needed to ensure load balancing at a particular bus b for operating period t on day d is settled at the LMP determined for bus b in the RTM SCED optimization conducted for operating period t on day d.

For later purposes, four key features of this existing wholesale power market design need to be stressed. First, the design does not provide for the coverage of UC costs through market-based processes. Rather, start-up/shut-down, no-load, and other forms of UC costs incurred by GenCos are compensated by various forms of *out-of-market (OOM)* payments, generally referred to as *uplift payments*.

Second, DAM/RTM settlements (including uplift payments) do not carefully distinguish between avoidable costs and unavoidable (sunk) costs. All of the avoidable costs incurred by DAM/RTM market participants due to their fulfillment of DAM/RTM service obligations should be compensated through DAM/RTM settlements. However, the unavoidable costs of these participants – i.e., the costs they

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the load (power demands) of its retail customers. An ISO/RTO is an organization charged with the primary responsibility of maintaining the security of an electric power system and often with system operation responsibilities as well. The ISO/RTO is required to be independent, meaning it cannot have a conflict of interest in carrying out these responsibilities, such as an ownership stake in generation or transmission facilities within the power system.

[9] LMP is the pricing of electric power according to the timing and location of its withdrawal from, or injection into, an electric power grid.

[10] These system constraints include: power balance constraints; line and generation capacity limits; down/up ramping restrictions; minimum down/up-time requirements, and reserve requirements.

would incur whether or not they participated in the DAM/RTM – should not be compensated through DAM/RTM settlements.

Third, settlement obligations for scheduled next-day service performance are incurred in the DAM in advance of actual service performance. These DAM settlement obligations are based on DAM net load estimates formed from LSE demand bids and from ISO/RTO forecasts for next-day non-dispatchable generation. Thus, subsequent RTM dispatch and settlement adjustments are typically needed in order to balance *actual* next-day net loads. Having multiple points in time (DAM, RTM) at which settlement obligations are incurred for the same operating period increases the chance that market inefficiency (deadweight loss) will arise.

Fourth, considered together, the above three features result in extremely complex market rules. This, in turn, opens up opportunities for market gaming.

4 The SC DAM Design: Overview

As discussed in [15, 22], swing contract (SC) trading can be supported by a sequence of linked centrally-managed forward markets whose planning horizons range from years to minutes. Forward markets with very long planning horizons can be used to encourage new capacity investment while forward markets with very short planning horizons can be used to correct last-minute imbalances between available generation and forecasted real-time net loads.

In this study, for concreteness, we demonstrate how an ISO-managed *SC DAM* can be designed that permits SC trading by the set $\mathbb{M}$ of all market participants with dispatchable resources. The entities in $\mathbb{M}$ can include GenCos, demand response resources (DRRs),[11] electric storage devices (ESDs), and dispatchable variable energy resources (VERs). Additional market participants include non-dispatchable VERs and LSEs with fixed (must-serve) loads.

To retain the ISO's non-profit status, all costs incurred by the ISO for SC procurement must be passed through to market participants. This cost pass-through could simply require all procurement costs to be allocated to the LSEs in proportion to their share of real-time loads. However, the presence of performance payment methods ϕ in offered SCs permits more sophisticated cost-sharing arrangements. For example, reserve requirement costs could arise in part due to the inability of some resources with cleared SCs to follow dispatch instructions with high accuracy. The ISO could require standardized failure-to-perform penalties to be included in the performance payment methods of SCs to help defray these costs.

Figure 3 provides a summary comparison of our proposed SC DAM design to current DAM designs. The basic features characterizing current DAM designs are

[11] An example of a DRR would be an entity that manages a collection of *distributed energy resources (DERs)*, such as household appliances. Even if individual DERs have relatively small amounts of down/up flexibility in their power usage due to local goals and constraints, a sufficiently large collection of these DERs could permit the extraction of down/up demand response services with substantial flexibility.

		Current DAM	Proposed SC DAM
Similarities		• Conducted day-ahead to plan for next-day operations • ISO-managed • MPs can include GenCos, DRRs, ESDs, VERs, & LSEs • Subject to same physical constraints: e.g. transmission, generation, ramping, & power-balance constraints	
Differences	• Optimization formulation	SCUC & SCED	Contract-clearing
	• Settlement	Locational marginal pricing	Availability prices
	• Payment	Payment for next-day service before actual performance	Payment for availability now & performance ex post
	• Out-of-market payments	Uplift payments (e.g., for unit commitment costs)	No out-of-market payments
	• Information given to MPs	Unit commitments, LMPs, & next-day dispatch schedule	Which contracts have been cleared

Fig. 3 Comparison of the SC DAM design with current DAM designs.

explained in Section 3. To understand the similarities and differences highlighted in Fig. 3, it is important to recall the key attributes of SCs discussed in Section 2. These key attributes are summarized below.

(i) The swing in the contractual terms of SCs permits these contracts to function as both power and reserve products. This eliminates the need to provide separate pricing and settlement processes for power versus reserve services.

(ii) The two-part pricing of SCs permits full separate market-based compensation for service availability and service performance. The availability price of an SC permits the seller to be compensated for all avoidable costs associated with service availability, while the performance payment method included among the terms of an SC permits the seller to be compensated ex post for all avoidable costs arising from actual real-time service provision.

(iii) SCs require sellers to internally manage unit commitment and generation capacity constraints for their resources. By offering an SC into an SC DAM, a seller is communicating to the ISO in charge of this SC DAM that it can feasibly perform the services represented in the SC if called upon to do so.

(iv) The performance payment method ϕ included among the contractual terms of an SC can designate special incentives and/or penalties to assure the ISO that the seller of the SC will fulfill the terms of the SC if the SC is cleared.

5 The SC DAM Design: Analytical Formulation

5.1 SC DAM Analytical Formulation: Summary Description

As discussed in Section 3, current DAM designs rely on standard SCUC/SCED optimizations to determine unit commitment, economic dispatch, and pricing solutions. In a sharp break from this practice, we propose a new analytical optimization formulation for the SC DAM that permits the optimal clearing of SCs.

		SCUC	SCED	Proposed SC DAM
Similarities		• Both SCUC and the proposed SC DAM are solved as mixed integer linear programming (MILP) problems subject to physical constraints		
Differences	• Objective	Min {Start-Up /Shut-Down Costs + No-Load Costs + Dispatch Costs + Reserve Costs}	Min {Dispatch Costs + Reserve Costs}	Min {Availability Cost + Expected Performance Cost}
	• Start-up & shut-down constraints	Yes	No	Start-up/shut-down constraints are implicit in submitted contracts
	• Primary decision variables	Unit commitments	Energy dispatch & reserve levels	Cleared contracts
	• Settlement	No	LMPs calculated as SCED dual variables	Availability prices paid for cleared contracts

Fig. 4 Comparison of the SC DAM optimization formulation with current SCUC/SCED DAM optimization formulations.

Figure 4 highlights key distinctions between our proposed optimization formulation for the SC DAM and traditional SCUC/SCED optimization formulations. Section 5.2 clarifies these distinctions by setting out our proposed SC DAM optimization formulation in concrete equation form.

5.2 SC DAM Analytical Formulation: Equations

Consider an ISO-managed SC DAM to be optimally cleared over a set $\mathbb{T} = \{1,\ldots,T\}$ of successive next-day operating periods t with length Δt. For clarity of exposition, five assumptions are made.

First, it is assumed that all loads serviced by the LSEs are fixed (must-serve) loads that do not provide dispatchable services. Second, it is assumed that LSE demand bids have a simple block-energy form, i.e., an LSE's demand bid for any given period t consists of a power demand (MW) that is not responsive to price. Third, it is assumed that each market participant m with dispatchable resources, i.e., each $m \in \mathbb{M}$, offers a single swing contract SC_m into the SC DAM, where SC_m takes form (1).[12] Fourth, it is assumed that the performance payment method ϕ_m appearing within SC_m takes the form of a collection of flat-rate energy prices $\phi_m(t)$ (\$/MWΔt), one price for each $t \in \mathbb{T}$. Fifth, it is assumed that only system-wide down/up spinning reserve requirements are imposed; contingency reserve requirements for generator or line outages are not considered.[13]

Given these simplifications, the objective of the ISO managing the SC DAM reduces to the minimization of total cost (\$) over $\mathbb{T}$ subject to system constraints. *Total cost* is the summation of SC availability cost plus expected performance cost arising from the need to balance expected net loads $\{NL_b(t) : b \in \mathbb{B}, t \in \mathbb{T}\}$ as determined by LSE demand bids and ISO-forecasted generation from non-dispatchable VERs. Total cost is expressible as follows:[14]

$$\sum_{m\in\mathbb{M}} \alpha_m c_m + \sum_{t\in\mathbb{T}} \sum_{m\in\mathbb{M}} \phi_m(t)|p_m(t)|\Delta t \tag{2}$$

The ISO minimizes (2) by appropriate selection of the following ISO decision variables:

- *Market participant contract clearing indicators:*

$$c_m \in \{0,1\}, \ \ \forall m \in \mathbb{M}$$

- *Market participant power dispatch levels:*

$$p_m(t), \ \ \forall m \in \mathbb{M}, \ t \in \mathbb{T}$$

- *Bus voltage angles:*

$$\theta_b(t), \forall b \in \mathbb{B}, t \in \mathbb{T}$$

The system constraints for the minimization of (2) are as follows:

ISO decision variable bounds:

$$c_m \in \{0,1\}\,, \qquad \forall m \in \mathbb{M} \tag{3}$$

$$-\pi \leq \theta_b(t) \leq \pi\,, \qquad \forall b \in \mathbb{B}, t \in \mathbb{T} \tag{4}$$

[12] See [15] for a discussion of the more general case in which offers can take the form of portfolios consisting of multiple SCs.

[13] As discussed in [15], option SCs seem to be a more suitable vehicle than firm SCs for handling contingency reserve requirements.

[14] See the appendix nomenclature table for definitions of all terms appearing in the following equations. Although power levels $p_m(t)$ for all market participants $m \in \mathbb{M}$ nominally appear in the objective function (2), it will be seen below that the constraints for this SC DAM optimization formulation restrict the power amounts for market participants with non-cleared SCs to be zero.

Unit commitment constraints:

$$v_m(t) = c_m \cdot A_m(t), \qquad \forall\, m \in \mathbb{M},\ t \in \mathbb{T} \tag{5}$$

Voltage angle specification at angle reference bus 1:

$$\theta_1(t) = 0, \qquad \forall t \in \mathbb{T} \tag{6}$$

Line power transmission constraints:

$$w_\ell(t) = S_o B(\ell)\left[\theta_{O(\ell)}(t) - \theta_{E(\ell)}(t)\right],\ \forall \ell \in \mathbb{L},\ t \in \mathbb{T} \tag{7}$$

$$-F_\ell^{max} \le w_\ell(t) \le F_\ell^{max}, \qquad \forall \ell \in \mathbb{L},\ t \in \mathbb{T} \tag{8}$$

Power balance constraints at each bus:

$$\sum_{m \in \mathbb{M}_b} p_m(t) + \sum_{\ell \in \mathbb{L}_{E(b)}} w_\ell(t) = NL_b(t) + \sum_{\ell \in \mathbb{L}_{O(b)}} w_\ell(t), \qquad \forall b \in \mathbb{B},\ t \in \mathbb{T} \tag{9}$$

Market participant capacity constraints:

$$\underline{p}_m(t) \le p_m(t) \le \bar{p}_m(t), \qquad \forall m \in \mathbb{M},\ t \in \mathbb{T} \tag{10}$$

$$\bar{p}_m(t) \le P_m^{max} v_m(t), \qquad \forall m \in \mathbb{M},\ t \in \mathbb{T} \tag{11}$$

$$\underline{p}_m(t) \ge P_m^{min} v_m(t), \qquad \forall m \in \mathbb{M},\ t \in \mathbb{T} \tag{12}$$

Market participant down/up ramp constraints:

$$\bar{p}_m(t) - p_m(t-1) \le R_m^U \Delta t v_m(t-1) + P_m^{max}[1 - v_m(t-1)], \qquad \forall m \in \mathbb{M},\ \forall t = 2, \cdots, T \tag{13}$$

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

System-wide down/up spinning reserve requirement constraints:

$$\sum_{m \in \mathbb{M}} \overline{p}_m(t) \ge \sum_{b \in \mathbb{B}} NL_b(t) + RR^U(t),\ \ \forall t \in \mathbb{T} \tag{15}$$

$$\sum_{m \in \mathbb{M}} \underline{p}_m(t) \le \sum_{b \in \mathbb{B}} NL_b(t) - RR^D(t),\ \ \forall t \in \mathbb{T} \tag{16}$$

5.3 More Detailed Explanations of Key Terms

The absolute value terms $|p_m(t)|$ appear in the objective function (2) because a market participant m with dispatchable resources might be called upon to provide power curtailments $p_m(t) < 0$ as well as power injections $p_m(t) > 0$ in support of period-t net load balancing requirements. The power curtailments provided by m are assumed to be compensated at the same flat rate $\phi_m(t)$ as m's power injections.[15]

The contract clearing indicator $c_m \in \{0,1\}$ indicates whether SC$_m$ has been cleared (1) or not (0). The offer service indicator $A_m(t) \in \{0,1\}$ indicates whether time period t is (1) or is not (0) within the contract service times covered by SC$_m$.

Note that $A_m(t)$ is a derived value, calculated by the ISO from the information provided within SC$_m$. Consider, for example, the numerical SC example presented in Section 2. In this example, a market participant m submits an SC consisting of an offer to provide service between 8:00am and 10:00am during the following day. Thus:

$$A_m(t) = \begin{cases} 1 & \text{if t = 8, 9} \\ 0 & \text{if t = 1, \ldots, 7, 10, \ldots, 24} \end{cases}$$

As seen in Section 5.2, the unit commitment constraints take the form

$$v_m(t) = c_m \cdot A_m(t), \qquad \forall\, m \in \mathbb{M},\ t \in \mathbb{T} \tag{17}$$

The unit commitment $v_m(t) \in \{0,1\}$ for each market participant $m \in \mathbb{M}$ in each time period t is thus determined by two factors:

(a) Has SC$_m$ been cleared by the ISO or not?
(b) Does SC$_m$ include service for time period t or not?

The contract clearing indicator $c_m \in \{0,1\}$ represents condition (a), and the offer service indicator $A_m(t) \in \{0,1\}$ represents condition (b). If conditions (a) and (b) are both met, then m is available to provide service in time period t. Otherwise, if at most one of these conditions is met, m is not available to provide service in time period t.

The market participant capacity constraints take the form

$$\underline{p}_m(t) \le p_m(t) \le \bar{p}_m(t), \qquad \forall m \in \mathbb{M},\ t \in \mathbb{T} \tag{18}$$
$$\bar{p}_m(t) \le P_m^{max} v_m(t), \qquad \forall m \in \mathbb{M},\ t \in \mathbb{T} \tag{19}$$
$$\underline{p}_m(t) \ge P_m^{min} v_m(t), \qquad \forall m \in \mathbb{M},\ t \in \mathbb{T} \tag{20}$$

[15] The absolute value terms $|p_m(t)|$ in the objective function (2) do not pose any computational difficulty. Because the goal is to minimize this objective function, these absolute value terms can equivalently be represented in terms of linear inequality constraints, as follows. First, introduce new decision variables for the ISO: $p^a_m(t), \forall m \in \mathbb{M},\ t \in \mathbb{T}$. Second, in the objective function (2), replace $|p_m(t)|$ by $p^a_m(t)$, $\forall m \in \mathbb{M},\ t \in \mathbb{T}$. Third, include the following additional linear inequality constraints in the constraint set: $p^a_m \ge p_m$ and $p^a_m \ge -p_m$, $\forall m \in \mathbb{M}, t \in \mathbb{T}$. Any solution for the resulting constrained minimization problem will then require $p^a_m(t) = |p_m(t)|$, $\forall m \in \mathbb{M}, t \in \mathbb{T}$.

Also, the market participant down/up ramp constraints take the form

$$\bar{p}_m(t) - p_m(t-1) \leq R_m^U \Delta t v_m(t-1) + P_m^{max}[1 - v_m(t-1)],$$
$$\forall m \in \mathbb{M},\ \forall t = 2,\cdots,T \tag{21}$$
$$p_m(t-1) - \underline{p}_m(t) \leq R_m^D \Delta t v_m(t) + P_m^{max}[1 - v_m(t)], \tag{22}$$
$$\forall m \in \mathbb{M},\ \forall t = 2,\cdots,T \tag{23}$$

The terms $\underline{p}_m(t)$ and $\bar{p}_m(t)$ appearing in constraints (18) through (23) are derived values; they give the run-time lower and upper bounds on down/up power availability from market participant $m \in \mathbb{M}$ in each time period $t = 2,\ldots,T$ as a function of the ISO's unit commitment decisions $v_m(t-1)$ and $v_m(t)$.

To see this, note from (18)-(20) that $v_m(t) = 0$ implies $p_m(t) = 0$ for each $t \in \mathbb{T}$. Also, the binary unit commitment vector ($v_m(t-1)$,$v_m(t)$) can take on only one of four possible value combinations for $t = 2,\ldots,T$: namely, (0,0), (1,0), (0,1), or (1,1). Given each of these four possible value combinations, it is straightforward to show that constraints (18) through (23) reduce to a distinct set of restrictions on ($\underline{p}_m(t)$,$\bar{p}_m(t)$) for $t = 2,\ldots,T$, as indicated in Table 1.

Table 1 Min/max available power output from m under different unit commitment combinations.

$v_m(t)$	0	0	1	1
$v_m(t-1)$	0	1	0	1
$\bar{p}_m(t)$	0	0	$\bar{p}_m(t) \leq P_m^{max}$	$\bar{p}_m(t) \leq P_m^{max}$ $\bar{p}_m(t) \leq p_m(t-1) + R_m^U \Delta t$
$\underline{p}_m(t)$	0	0	$\underline{p}_m(t) \geq P_m^{min}$	$\underline{p}_m(t) \geq P_m^{min}$ $\underline{p}_m(t) \geq p_m(t-1) - R_m^D \Delta t$

Finally, it is interesting to note that an "inherent reserve range" can be derived for the power system in each time period t, as a function of the solution for the SC DAM optimization. Define

$$RR^{max}(t) = \sum_{m \in \mathbb{M}} \overline{p}_m(t), \qquad \forall t \in \mathbb{T} \tag{24}$$
$$RR^{min}(t) = \sum_{m \in \mathbb{M}} \underline{p}_m(t), \qquad \forall t \in \mathbb{T} \tag{25}$$

By construction, the MW amounts $RR^{max}(t)$ and $RR^{min}(t)$ are the maximum and minimum amounts of power available for the system in each time period t during implementation of the SC DAM optimization solution. The *Inherent Reserve Range (IRR)* for time period t thus takes the form

$$IRR(t) = [RR^{min}(t), RR^{max}(t)]\,. \tag{26}$$

5.4 Size Comparison with Standard DAM SCUC Formulations

As noted in Section 3, two optimizations are undertaken in current U.S. ISO/RTO-managed DAMs to determine unit commitment, economic dispatch, and pricing solutions: namely, *Security-Constrained Unit Commitment (SCUC)* and *Security-Constrained Economic Dispatch (SCED)*. SCUC is formulated as a *mixed integer linear programming (MILP)* problem and SCED is formulated as a linear programming problem.

Instead of conducting two optimizations, our proposed new SC DAM optimization uses a single optimization process to determine which SCs are cleared, hence which dispatchable market participants are obligated (committed) to ensure service availability for the following day. As seen in Section 5.2, this SC DAM optimization is formulated as an MILP problem.

The sizes of the standard DAM SCUC MILP problem and the SC DAM MILP problem can be approximately measured by the number of integer decision variables and constraints in their problem formulations. To permit direct comparisons, suppose the current day is d and the planning horizon for each problem consists of all 24 hours h of day d+1.

Consider, first, the relative number of integer decision variables. For the DAM SCUC MILP problem, the ISO has 24 integer decision variables (unit commitment indicators) for each market participant m with dispatchable resources, one for each hour h of day d+1. In contrast, for the SC DAM MILP problem, the ISO has one integer decision variable (contract clearing indicator) for each market participant m with dispatchable resources that covers the entire 24 hours of day d+1.

Now consider the relative number of constraints. For the standard DAM SCUC MILP problem, unit commitment restrictions (e.g., start-up/shut-down, minimum down/up time) must be included among the MILP problem constraints. In contrast, for the SC DAM MILP problem, each market participant m is responsible for ensuring the physical feasibility of SC_m, its offered swing contract, which requires in particular that all services offered in SC_m must satisfy m's unit commitment restrictions. Thus, unit commitment restrictions are implicitly imposed through the forms of the submitted SCs; they do not appear among the MILP problem constraints.

Consequently, measured in terms of integer decision variables and numbers of constraints, the size of the SC DAM optimization formulation is smaller than the size of the standard DAM SCUC optimization formulation, substantially so if the number of dispatchable market participants is large.

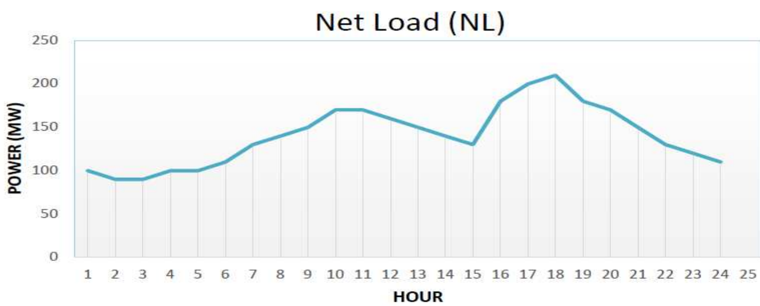
6 Illustrative Example

This section reports illustrative SC DAM optimization findings for a simple power system with three dispatchable GenCos and no transmission congestion. Each GenCo m submits one swing contract SC_m to the ISO-managed SC DAM, as depicted in Table 2.

Table 2 SCs submitted by the three GenCos in the illustrative example.

GenCo	Service Period $[t_s, t_e]$	Power Range $[P^{min}, P^{max}]$ (MW)	Ramp Rate Range $[-R^D, R^U]$ (MW/h)	Performance Price ϕ ($/MWh)	Availability Price α ($)
1	[1, 24]	[0, 80]	[-60, 60]	25	1500
2	[1, 24]	[0, 200]	[-30, 30]	10	2000
3	[8, 24]	[0, 120]	[-50, 50]	20	1000

Time periods t are measured in hours, and the net load $NL(t)$ for each hour t of the following day is as depicted in Fig. 5. The system-wide down/up spinning reserve requirements are set at 10MW below/above net load for each hour t, i.e., $RR^D(t) = RR^U(t) = 10$MW for each hour t.



Hr	1	2	3	4	5	6	7	8	9	10	11	12
NL	100	90	90	100	100	110	130	140	150	170	170	160
Hr	13	14	15	16	17	18	19	20	21	22	23	24
NL	150	140	130	180	200	210	180	170	150	130	120	110

Fig. 5 24-hour net load profile for the illustrative example.

The ISO applies an MILP solver to determine an SC DAM optimization solution for the following day, conditional on the three submitted SCs. Simulation results show that the SCs submitted by GenCo 2 and GenCo 3 are cleared: i.e., $c_{m1} = 0$, $c_{m2} = 1$, and $c_{m3} = 1$. The optimal unit commitment $v_m(t)$ and dispatch level $p_m(t)$ for each GenCo m in each hour t are shown in Tables 3 and 4, respectively.

The DAM prices for the cleared SCs are their submitted availability prices, and the payments to be received for any actual services performed under these SCs the following day are based on the energy prices specified by the cleared SC performance payment methods: that is, ϕ_{m2} = \$10/MWh and ϕ_{m3} = \$20/MWh.

The results show that GenCo 2 serves as base load due to its relatively low performance price, similar to a coal or nuclear plant. The reasons why GenCo 3's submitted SC is also cleared are as follows. First, there is a big ramp-up in net load from hour 15 to hour 16. Due to GenCo 2's limited ramp capability, the maximum available power output for GenCo 2 at hour 16 is 160MW. Thus, GenCo 3 is cleared although it is relatively more expensive. Second, the net load for hour 18 is 210MW,

Table 3 Optimal SC DAM unit commitments for the illustrative example.

GenCo	Periods																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 4 Optimal SC DAM dispatch schedule (MWs) for the illustrative example.

GenCo	Periods																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	100	90	90	100	100	110	130	140	150	170	170	160	150	140	130	160	190	200	180	170	150	130	120	110
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	10	10	0	0	0	0	0	0

which exceeds GenCo 2's upper output limit 200MW. Thus, GenCo 3 is needed to provide additional power.

Although GenCo 3's available power is not used until hour 16, the unit commitment for GenCo 3 in fact spans from hour 8 to hour 24. The reason for this is that GenCo 's SC commits this GenCo to be available to provide power from hour 8 through hour 24. Thus, if the ISO clears the contract, GenCo 3 must be synchronized to the grid during each of these hours.[16]

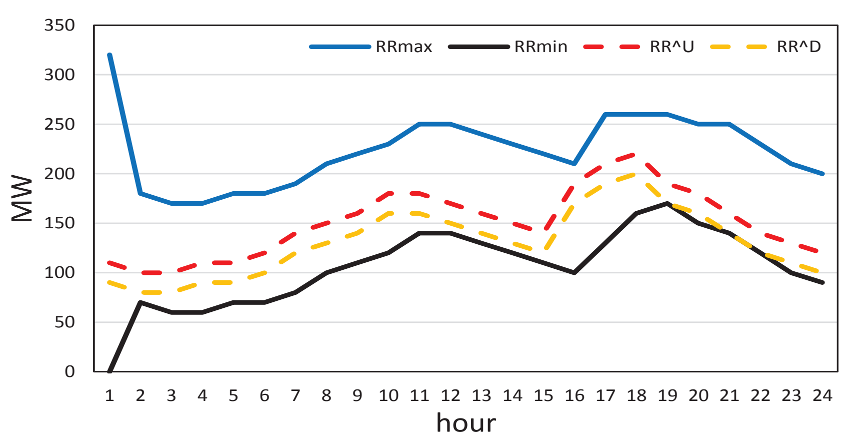


Fig. 6 Comparison of the 24-hour inherent reserve range $IRR = [RR^{min}, RR^{max}]$ depicted by solid lines with the 24-hour down/up spinning reserve requirements RR^D and RR^U depicted by dashed lines.

[16] As in any market, increased competition among SC providers should reduce the need of an ISO to clear SCs that entail excess resource availability.

Figure 6 depicts the inherent reserve range resulting from the cleared SCs for GenCo 2 and GenCo 3, together with the down/up spinning reserve requirements. Note that the inherent reserve range satisfies the down/up spinning reserve requirements while at the same time providing valuable additional flexibility to the ISO for use in real-time balancing operations.

7 Conclusion

A new mixed-integer linear programming (MILP) optimization formulation has been developed for an ISO-managed day-ahead market (DAM) based on swing contracting that could facilitate the flexible provision and efficient pricing of power and reserve services. A limitation of the current study is that we have not yet implemented and tested our proposed new SC market design for large-scale systems, or for systems involving a DAM and a real-time market (RTM) operating in parallel.

In future work we will extend our SC market design formulation to encompass combined DAM/RTM operations, and we will undertake systematic feasibility and cost comparisons with existing DAM/RTM operations. We will also explore the potential of swing contracts, offered into wholesale power markets by managers of distributed energy resources, to facilitate the integrated operation of transmission and distribution systems.

Acknowledgements This research has been supported in part by grants from the ISU Electric Power Research Center (EPRC), Sandia National Laboratories (Contract No. 1163155), and the Department of Energy (DE-AR0000214 and DE-OE0000839). The authors are grateful to the editors and four reviewers for constructive comments, and to Zhaoyu Wang and Shanshan Ma for helpful discussions related to the topic of this study.

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Appendix

Table 5 Nomenclature table listing symbols and symbol descriptions.

Symbol	Description
***Sets and Intervals*:**	
$\mathbb{B}$	Set of bus indices b
$\mathbb{L} \subset \mathbb{B} \times \mathbb{B}$	Set of transmission line indices ℓ
$\mathbb{L}_{O(b)} \subset \mathbb{L}$	Subset of lines ℓ originating at bus b
$\mathbb{L}_{E(b)} \subset \mathbb{L}$	Subset of lines ℓ ending at bus b
$\mathbb{M}$	Set of indices m for market participants with dispatchable resources
$\mathbb{M}_b \subset \mathbb{M}$	Market participants at bus b with dispatchable resources
$\mathscr{P}$	Interval of power levels p offered in a swing contract
$\mathscr{R}$	Interval of ramp rates r offered in a swing contract
$\mathbb{T}$	Set of time period indices $t = 1, \ldots, T$
***Parameters and Functions*:**	
$A_m(t)$	1 if m in time period t is within its contract service period; 0 otherwise
$B(\ell)$	Inverse of reactance (pu) for line ℓ
$E(\ell)$	End bus for line ℓ
F_ℓ^{max}	Power limit (MW) for line ℓ
$NL_b(t)$	Net load (MW) at bus b in time period t
$O(\ell)$	Originating bus for line ℓ
P_m^{min}	Lower power limit (MW) of m
P_m^{max}	Upper power limit (MW) of m
R_m^D	Ramp-down limit (MW/Δt) of m
R_m^U	Ramp-up limit (MW/Δt) of m
$RR^D(t)$	System-wide down spinning reserve requirement (MW) in time period t
$RR^U(t)$	System-wide up spinning reserve requirement (MW) in time period t
S_o	Positive base power (in three-phase MVA)
t_e	Power delivery end time offered in a swing contract
t_s	Power delivery start time offered in a swing contract
Δt	Time-period length
α_m	Availability price ($) requested by m for a swing contract that offers service availability
ϕ	Performance payment method for real-time service offered in a swing contract
$\phi_m(t)$	Energy price ($/MW$\Delta t$) used in illustrative SC examples as a simple form of performance payment method for the compensation of real-time down/up power services performed by a market participant m
***SC DAM Optimization Variables*:**	
c_m	1 if the swing contract offered by m is cleared; 0 otherwise
$v_m(t)$	1 if m is online in time period t; 0 otherwise
$p_m(t)$	Power output (MW) of m in time period t
$\overline{p}_m(t)$	Maximum available power output (MW) of m in time period t
$\underline{p}_m(t)$	Minimum available power output (MW) of m in time period t
$\theta_b(t)$	Voltage angle (radians) at bus b in time period t
$w_\ell(t)$	Line power (MW) for line ℓ in time period t