Facilitating appropriate compensation of electric energy and reserve through standardized contracts with swing

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Abstract

Three key issues have arisen for centrally-managed wholesale electric power markets in Europe and the United States as they attempt to handle an increased penetration of variable energy resources. First, rigid definitions for energy and reserve products make it difficult to ensure appropriate compensation for important needed flexibility in start-up times, ramp-rates, power dispatch levels, and duration. Second, participation restrictions hinder the achievement of an even playing field for potential providers of flexible services. Third, reliance on out-of-market compensation for the provision of some valued services encourages strategic manipulation. This study examines the possibility of addressing these three issues through the introduction of standardized energy and reserve contracts with swing (flexibility) in their contractual terms. Concrete examples are used to demonstrate how the trading of these standardized contracts can be supported by linked forward markets in a manner that permits efficient real-time balancing of net load subject to system and reserve-requirement constraints. Comparisons with existing wholesale electric power markets are given, and key policy implications are highlighted.

Keywords: Electric power markets, variable energy resources, standardized contracts, swing (flexibility), energy and reserve co-optimization, linked forward markets

1 Introduction

European and U.S. electricity sectors have undergone substantial restructuring over the past twenty years. They have devolved from highly regulated systems operated by vertically integrated utilities to relatively decentralized systems based more fully on market valuation and allocation mechanisms.

As part of this restructuring, oversight agencies have been established at several different levels to encourage cooperation and coordination. The European Network of Transmission System Operators for Electricity (ENTSO-E), founded in 2008, currently consists of forty-one Transmission System Operators (TSOs) from thirty-four European countries; its primary task is to promote the coordinated management of the European power grid (ENTSO-E 2015). The U.S. Federal Energy Regulatory Commission (FERC) oversees the activities of six of the seven U.S. Independent System Operators (ISOs), established since the mid-1990s, that manage power system operations in electric energy regions comprising approximately 60% of U.S. generating capacity (EIA 2015).[1]

These restructuring efforts have been driven by a desire to ensure efficient energy production and utilization, reliable energy supplies, affordable energy prices, and effective rules and regulations for environmental protection. In keeping with the latter goal, a dramatic change is taking place in energy mixes: namely, a rapid penetration of variable energy resources combined with a movement away from traditional thermal generation.

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. Consequently, the integration of VERs tends to increase the volatility of net load (ie, load minus as-available generation) as well as the frequency of strong ramp events. Flexibility in service provision by other types of resources then becomes increasingly important to maintain the reliability and efficiency of power system operations.

To accommodate increased VER penetration, TSOs and ISOs have introduced major changes in their market rules and operational procedures (ENTSO-E 2014; Henry et al 2014; Ela 2011; NREL 2012). These changes have included new products to enhance net load following capability (eg, ramping products), revised market eligibility requirements to encourage greater VER participation, and the introduction of capacity markets in an attempt to ensure sufficient thermal generation as a backstop for the intermittency of VER generation.

Nevertheless, several important issues arising from increased VER penetration still need to be resolved. One key issue is that energy and reserve products are variously defined and compensated across the different energy regions; see, eg, Ellison et al (2012). This makes it difficult to compare and evaluate the efficiency and fairness of system operations across these regions.

A second key issue is appropriate compensation for flexibility in service pro-

[1] One U.S. ISO, the Electric Reliability Council of Texas (ERCOT), is not under FERC jurisdiction because its grid has been deliberately designed to avoid interstate commerce transactions that would subject it to U.S. Federal jurisdication (Spence and Bush, 2009).

vision. TSO/ISO product definitions are specified in broad rigid terms (eg, capacity, energy, ramp-rate, regulation, non-spinning reserve) that 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.

A third key issue is that attempts to accommodate new products have led to the introduction of out-of-market (OOM) compensation processes. In 2011 FERC issued Order 755 to address OOM payment problems for one particular product category in U.S. ISO-managed wholesale power markets: namely, regulation with different abilities to follow electronic dispatch signals with high accuracy (FERC 2011). However, given its limited scope, Order 755 does not fully eliminate the need in these markets to resort to OOM processes. As stressed by Bushnell (2013), the additional complexity resulting from OOM compensation processes provides increased opportunities for market participants to gain unfair profit advantages through strategic behaviors.

In response to these issues, a group of researchers sponsored by Sandia National Laboratories prepared a report (Tesfatsion et al 2013) recommending that energy and reserve contracts be standardized in firm and option forms permitting separate pricing for service availability and for real-time service performance, and that the trading of these contracts be supported by a linked sequence of forward markets whose design is also standardized. This report builds on important earlier work by Bidwell (2005), Bunn (2004), Chao and Wilson (2002), and Oren (2005), who stress the relevance of options and two-part pricing for electricity markets.

The current study uses concrete numerical examples to explore the policy implications of the recommendations in Tesfatsion et al (2013). In Section 2 we present a general template for a *Standardized Contract (SC)* with swing (flexibility) in its contractual terms, together with an illustrative SC example. We also outline in broad terms how the trading of SCs can be supported by linked centrally-managed day-ahead and real-time markets. In Section 3 and Section 4 we present our main results: namely, examples demonstrating how our proposed SC system, implemented via linked day-ahead and real-time markets, permits efficient real-time balancing of net load subject to system and reserve-requirement constraints.

Comparisons of our proposed SC system with existing European and U.S. wholesale power market operations, standardized power contracts, pricing mechanisms, and VER initiatives are provided in Sections 5.1-5.4. In Section 5.5 we discuss how our SC system provides a robust-control approach to the handling of uncertain net load that avoids the need to specify detailed scenarios with associated probabilities, a common requirement of standard stochastic control approaches. In Section 5.6 we conjecture how our proposed SC system, extended to longer-term forward markets, could help to provide better incentives for thermal generation capacity investment as a backstop for the intermittency of VER generation by facilitating the resolution of merit-order and missing-money problems.

Throughout Sections 2-5 the following key policy implications of our proposed SC system are highlighted:

- permits full market-based compensation for availability and performance
- facilitates a level playing field for market participation
- facilitates co-optimization of energy and reserve markets
- supports forward-market trading of energy 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 UC and capacity constraints
- permits the robust-control management of uncertain net load
- eliminates the need for OOM payment adjustments
- reduces the complexity of market rules

The concluding Section 6 provides a concise summary discussion of each of these policy implications.

2 Proposed Standardized Contract System

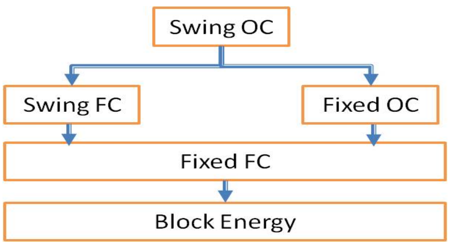
2.1 General Form of a Standardized Contract

Energy refers to the actual generation of electrical energy, whereas reserve refers to generation-capacity availability. Four standardized contracts are proposed in Tesfatsion et al (2013) to facilitate energy and reserve trading: namely, *firm contracts (FCs)* and *option contracts (OCs)* taking either fixed or swing form.

An FC is a non-contingent contract that requires specific performance from both counterparties. It obligates the holder to procure services from the issuer, and the issuer to deliver these services, under the contractually specified terms of the FC. In contrast, an OC gives the holder the right, but not the obligation, to procure services from the issuer under contractually specified terms. The right can be activated by exercise of the OC at a contractually permitted exercise time. Once exercised, an OC imposes specific performance obligations on both counterparties. That is, as for an FC, an exercised OC obligates the holder to procure services from the issuer, and the issuer to deliver these services, under the contractually specified terms of the OC.

An FC or OC is a *fixed* contract if each of its contractual terms is designated as a single possible value. An FC or OC is a *swing* contract if at least one of its contractual terms is designated as a set of possible values, thus permitting some degree of flexibility in its implementation. A fixed FC is a *block-energy* contract if its contractual terms obligate the issuer to maintain a specified constant power level during a specified time interval. As depicted in Fig. 1, fixed/swing OCs, fixed/swing FCs, and block-energy contracts are all special cases of swing OCs.

Figure 1: Hierarchical structure of contracts



Hereafter, this study focuses on *Standardized Contracts (SCs)* in swing-OC form for the flexible provision of energy and reserve services. For concreteness, we next present a template for an SC that provides seven basic types of services for a particular operating hour: delivery location; down/up direction; exercise time; power-begin time; power-end time; down/up ramp rate; and power level. We illustrate swing in five of these service types by depicting their sets of possible values as intervals.[2]

Template for a Standardized Contract (SC):

$$\text{SC} = [k, d, T_{ex}, T_{pb}, T_{pe}, R_C, P_C, \phi] \quad (1)$$

$k =$ Location where service delivery is to occur

$d =$ Direction (down or up)

$T_{ex} = [t_{ex}^{min}, t_{ex}^{max}] =$ Range of possible exercise times t_{ex}

$T_{pb} = [t_{pb}^{min}, t_{pb}^{max}] =$ Range of possible power-begin times t_{pb}

$T_{pe} = [t_{pe}^{min}, t_{pe}^{max}] =$ Range of possible power-end times t_{pe}

$R_C = [-r^D, r^U] =$ Range of possible down/up ramp rates r

$P_C = [p^{min}, p^{max}] =$ Range of possible power levels p

$\phi =$ Performance payment method for real-time service performance

The down/up limits $-r^D$ and r^U for the ramp-rates r (MW/min) are assumed to satisfy $-r^D \leq 0 \leq r^U$. The lower bound p^{min} for the power levels p (MW) is assumed to be non-negative. The direction (down or up) of an SC determines whether these power levels describe power curtailments or absorptions (down) or power injections (up). The time points t_{ex}, t_{pb}, and t_{pe} denote specific calendar times expressed at the granularity of minutes.

The presence of swing in the contractual terms of an SC permits this SC to function as both an energy and a reserve product. Actual real-time service performance under such an SC cannot be determined until after the end of the operating hour H even if the SC is a firm (non-optional) contract. Consequently,

[2] SCs can take much more general forms than illustrated in the current study. For example, SCs can include other types of services such as voltage control, reactive power support, and energy storage capacity; swing can be present in any of these services; swing possible value sets do not need to be in interval form; and the operating period does not need to be an hour.

the contractual terms of an SC include a performance payment method ϕ to be used to determine the ex-post payment to the SC issuer for real-time service performance (if any).

The performance payment method ϕ can take a wide variety of forms. For example, as illustrated in Section 3, ϕ might denote a pre-specified price ($/MWh) for delivered down/up energy. More generally, ϕ could denote a contingent price for delivered down/up energy that depends on market conditions (eg, fuel prices) at the time of the delivery. Alternatively, ϕ could provide for the compensation of delivered power measured as *mileage*, ie, as the sum of absolute-value up and down power movements over the real-time dispatch interval, a metric now being used for regulation service performance in many energy markets to meet the requirements of FERC Order 755 (Beacon Power 2014).

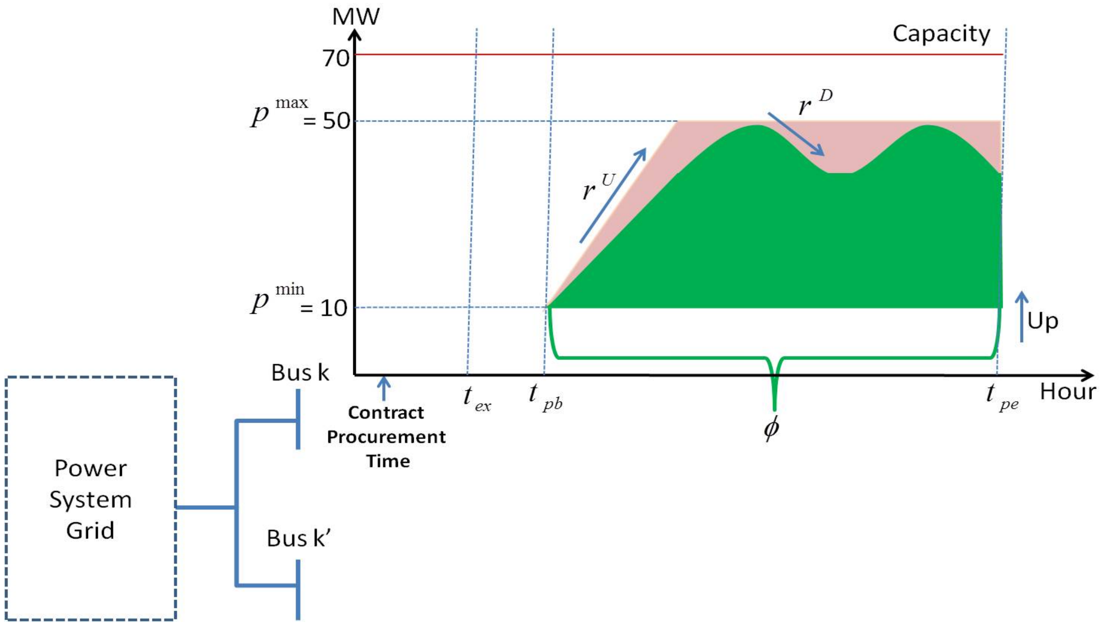
In order for an SC to be implementable, its contractual terms must satisfy certain basic requirements. For example, t_{pb}^{min} cannot exceed t_{pe}^{max}. In this study it is presumed that an SC issuer is responsible for ensuring that it can feasibly implement the terms of any SC it offers. Realistically, however, penalties and eligibility requirements might need to be introduced to help ensure that the issuers of cleared SCs accurately follow real-time dispatch instructions, and that these instructions are in accordance with the contractual terms of the cleared SCs. These contract enforcement mechanisms could constitute part of the performance payment method ϕ included within each SC, or they could be instituted at the level of the power system as a whole.

2.2 Illustrative Example of a Standardized Contract

The illustrative up-energy SC depicted in Fig. 2 provides a combination of fixed and swing attributes. The delivery location (bus k) and direction (up) are specified as single values, as are the exercise time t_{ex}, the power-begin time t_{pb}, and the power-end time t_{pe}. On the other hand, the down/up ramp rate r and the power level p are swing attributes that can be varied over a range of values.

The darker (green) area within the resulting corridor of contractually-admissible power dispatch paths depicted in Fig. 2 is the up-energy injection that results from one such path. Any actual up-energy injection is compensated ex post in accordance with the performance payment method ϕ included among the SC's contractual terms. An example of a down-energy SC can be obtained from Fig. 2 by considering a 180° rotation of the depicted figure around the time axis.

Figure 2: Example of an SC for up-energy with ramp-rate and power-level swing that is offered at bus k by a generator with a maximum capacity of 70MW



The SC depicted in Fig. 2 can be more concretely interpreted as an up-energy SC offered by a Demand Response Resource (DRR) into an ISO-managed day-ahead market (DAM) on day D-1 for a particular operating hour H on day D, as follows. Consider a Load Serving Entity (LSE) functioning as a load aggregator for a large distribution feeder connected to the transmission grid at a particular bus k. Residential households on this feeder have smart meters for their HVAC loads in wireless communication with the LSE that permits the LSE to make adjustments to these loads. The LSE has permission from each of these households to make small adjustments in their HVAC energy usage in return for an agreed-upon monthly lump-sum compensation. The LSE can participate in the DAM as a DRR either by offering up-energy implemented via HVAC load reductions or by offering down-energy implemented via HVAC load increases.

Suppose the LSE participates in the DAM on day D-1 as a DRR by offering the following up-energy SC at some offer price v for hour H of day D, where hour

H is the time interval between 1300EST and 1400EST:

- Delivery location = Bus k
- Direction = Up
- T_{ex} = Exercise time t_{ex} = 0900EST on day D
- T_{pb} = Power-begin time t_{pb} = 1300EST on day D
- T_{pe} = Power-end time t_{pe} = 1400EST on day D
- R_C = [-1.3MW/min, $+1.4$MW/Min] = Range of possible down/up ramp rates r
- P_C = [10MW, 50MW] = Range of possible power levels p
- ϕ = Payment method for compensation of delivered power mileage, including a penalty payment adjustment for deviations between instructed and actual power mileage

Suppose, also, that this SC is cleared by the ISO. The ISO is then obligated to ensure that the DRR receives in compensation its offer price v as payment for making available for hour-H operations on day D the services included in this SC. In turn, the ISO has the right, but not the obligation, to exercise this SC at 0900EST on day D.

If the SC is exercised, the DRR must be ready to follow any electronic dispatch signal on day D, starting at time t_{pb} = 1300EST and ending at time t_{pe} = 1400EST, that calls for the DRR to provide a path of power injections lying within its offered range P_C of power levels that can feasibly be achieved without violating the DRR's offered range R_C of down/up ramp rates. In turn, the ISO is obligated to ensure that the DRR is compensated ex post for the mileage of this controlled power path in accordance with the terms of the performance payment method ϕ.

2.3 Support of SC Trading via Linked Forward Markets

As in Tesfatsion et al (2013), we propose that SC trading be supported by a sequence of linked centrally-managed forward markets whose planning horizons can range from minutes to years. For concreteness, however, we focus in this study on the support of SC trading by means of linked day-ahead and real-time markets that are centrally managed by a non-profit *Independent System Operator (ISO)*; see Fig. 3.

Figure 3: Proposed ISO-managed day-ahead and real-time markets

Market Type	Participants	Contracts	Decision Variables	ISO Optimization Method
Day-Ahead Market (DAM)	LSEs	SC Block-Energy Bids	LSE SC Bids; Disp. GenCo / DRR / ESD SC Offers; ISO SC Bids	Security-Constrained Unit Commitment (SCUC) & Security-Constrained Economic Dispatch (SCED)
	Disp. GenCos, DRRs, and ESDs	SC Offers		
	Non-Disp. VERs	—		
	ISO	SC Bids		
Real-Time Market (RTM)	Disp. GenCos, DRRs, and ESDs	SC Offers	Disp. GenCo / DRR / ESD SC Offers; ISO SC Bids	SCED
	Non-Disp. VERs	—		
	ISO	SC Bids		

The non-ISO participants in our proposed day-ahead market (DAM) and real-time market (RTM) include: (i) *Load-Serving Entities (LSEs)* who submit SC demand bids in the form of block energy contracts on behalf of retail energy customers; (ii) dispatchable *Generation Companies (GenCos)*, *Demand Response Resources (DRRs)*, and *Energy Storage Devices (ESDs)* who submit SC supply offers; and (iii) non-dispatchable VERs whose as-available generation is treated as negative load.[3] The requirement that LSE SC demand bids be in block-energy form avoids the need for LSEs to exercise load-balancing discretion in the implementation of SCs with swing or option exercise times.

Participation in our proposed DAM/RTM processes is not meant to preclude electricity traders from procuring physical and financial instruments in power exchanges and over-the-counter power markets to hedge their price and volume

[3]As discussed in Section 5.4, our proposed SC system could be generalized to allow designated types of VERs to offer their generation as "dispatchable intermittent resources" in DAM/RTM operations, as is now being permitted in MISO (2011). However, this would raise a number of issues best left for future studies, eg, should VERs be charged or penalized the same as ordinary dispatchable generation for deviations from their cleared dispatch offers?

risks. However, physical instruments whose terms require the use of transmission line facilities must be self-scheduled and cleared in the DAM or RTM to ensure transmission availability and overall system reliability.

The ISO managing the DAM undertakes *Security-Constrained Unit Commitment (SCUC)* and *Security-Constrained Economic Dispatch (SCED)* conditional on LSE SC demand bids, ISO SC demand bids (for reserve procurement only), and SC supply offers from dispatchable GenCos, DRRs, and ESDs. 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 SC bids/offers permits more sophisticated arrangements. For example, an LSE's cost allocation could be based in part on its forecasting performance, measured ex post by comparing its cleared SC demand bids against the actual real-time loads of its customers; and an SC supplier's cost allocation could be based in part on the accuracy of its service performance, measured ex-post by examining how well it was able to follow real-time dispatch instructions.

The ISO's DAM SCUC/SCED objective is to minimize the expected total net cost of ensuring that sufficient generation is available to balance next-day forecasted net loads with suitable local and system-wide reserve buffers. Dispatchable generation availability is determined from dispatchable GenCo, DRR, and/or ESD supply offers. Next-day net load forecasts for power-balance purposes are determined from LSE SC demand bids and forecasted VER generation. Reserve buffers are ensured by ISO SC demand bids.

As usual, the DAM SCUC/SCED is subject to unit commitment (UC) conditions, generation-capacity limits, power-balance constraints, transmission-line limits, and both local and system-wide reserve-requirement constraints. However, the imposition of the UC conditions and generation-capacity limits occurs through the contractual terms of the DAM SC supply offers rather than through ISO-imposed constraints.

We also propose an ISO-managed RTM that runs a SCED every five minutes. Dispatchable GenCos, DRRs, and ESDs can offer SCs into the RTM. Only the ISO is permitted to procure these SCs, for balancing and reserve procurement purposes; and all ISO RTM procurement costs must be passed through to market participants in order to preserve the non-profit status of the ISO.

The ISO's RTM SCED objective is to minimize the expected total cost of ensuring that adequate generation is available to balance ISO-forecasted real-time net loads with suitable local and system-wide reserve buffers, given the existing inventory of previously-cleared SCs. This RTM SCED is subject to generation-capacity limits, power-balance constraints, transmission-line limits, and both local and system-wide reserve-requirement constraints. The imposition of the generation-capacity limits occurs through the contractual terms of the RTM SC supply offers rather than through ISO-imposed constraints.

SCs can provide a wide diversity of services through their contractual terms. As discussed in greater detail in Section 5.3, appropriate compensation for these diverse services requires a flexible pricing mechanism. Our DAM and RTM are therefore formulated as discriminatory-price auctions in which participants pay (or are paid) their bid/offer prices for cleared SCs. These bid/offer price payments are compensations for service availability. Any real-time service performance rendered through these cleared SCs is compensated ex post in accordance with the performance payment methods appearing among the contractual terms of the cleared SCs.

Finally, SCs with swing in their contractual terms can function as both energy and reserve, and SCs in option form can also function as reserve even if their contractual terms are fixed. Consequently, our proposed DAM and RTM intrinsically involve a co-optimization of energy and reserve.

The next two sections use concrete examples to demonstrate how SC trading can be supported by means of our proposed linked DAM and RTM processes in a way that ensures optimal balancing of real-time net loads subject to system and reserve-requirement constraints.

3 RTM Illustrative Example

3.1 Overview

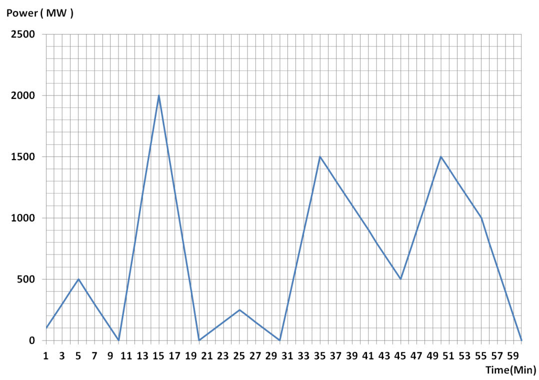
Sections 3.2 through 3.7 present a numerical example illustrating how SC trading can be supported by means of an RTM in the absence of transmission congestion and without consideration of linkages to earlier DAM processes. The handling of RTM transmission congestion is addressed in Section 3.8, and linkages with earlier DAM processes are considered in Section 4.

3.2 Basic Assumptions

Suppose an RTM takes place immediately prior to a particular operating period for which no congestion is anticipated. For concreteness, we assume this operating period is a particular hour H on a particular day D, expressed at the granularity of minutes.

Net load for hour H consists of aggregate load minus aggregate VER as-available generation. The net load profile for hour H that the ISO forecasts at the start of the RTM takes the form given in Fig. 4. The objective of the ISO managing the RTM is to ensure that this forecasted net load profile is balanced by generation with an appropriate reserve buffer, keeping costs to a minimum. The ISO attempts to achieve this objective by procuring a suitable combination of SCs from dispatchable generation suppliers participating in the RTM.

Figure 4: ISO-forecasted net load profile for hour H of day D at start of RTM



These dispatchable suppliers are assumed to consist of three GenCos with the following ramp-rate and generation-capacity attributes, expressed in Section 2.1 notation:

$$\text{G1}: \ r_1^D = r_1^U = 120\text{MW/min}, \text{Cap}_1^{min} = 0\text{MW}, \ \text{Cap}_1^{max} = 600\text{MW}$$
$$\text{G2}: \ r_2^D = r_2^U = 200\text{MW/min}, \text{Cap}_2^{min} = 0\text{MW}, \ \text{Cap}_2^{max} = 700\text{MW}$$
$$\text{G3}: \ r_3^D = r_3^U = 300\text{MW/min}, \text{Cap}_3^{min} = 0\text{MW}, \ \text{Cap}_3^{max} = 900\text{MW}$$

Each of these GenCo offers into the RTM a collection of portfolios, called *GenPorts*, together with associated GenPort offer prices. A GenPort consists of one or more SCs whose terms the GenCo could simultaneously fulfill during hour H if called upon to do so by the ISO. The ISO can clear at most one GenPort from each GenCo in the RTM.

The offer price $\text{v}_{i,j}$ for $\text{GenPort}_{i,j}$ is the payment requested by Gi for guaranteeing it will be available in hour H to fulfill the terms of the SCs included in $\text{GenPort}_{i,j}$ if signalled to do so. Thus, $\text{v}_{i,j}$ compensates Gi for service availability costs, such as avoidable fixed costs and lost opportunity costs. In addition, assuming $\text{GenPort}_{i,j}$ is cleared by the ISO, Gi will also receive performance payments for any services it renders during hour H under the contractual terms of the SCs in $\text{GenPort}_{i,j}$. Any such performance payments will be determined in accordance with the performance payment methods ϕ included among the contractual terms of the SCs in $\text{GenPort}_{i,j}$. For the example at hand, each of these performance payment methods ϕ is assumed to take the form of a pre-specified price ($/MWh) for delivered down/up energy.[4]

As clarified in subsequent sections, this two-part pricing scheme permits the GenCos to ensure the recovery of their expected total costs through a market process, taking into account their local attributes and conditions. It also permits the ISO to closely tailor the cleared RTM GenPorts to real-time needs for net load balancing subject to system and reserve-requirement constraints.

The ISO is permitted to clear at most one GenPort from each GenCo in the RTM. The resulting cleared GenPorts can thus be represented in the following

[4]For example, each $\text{SC}_{i,j,m}$ in $\text{GenPort}_{i,j}$ could correspond to a distinct generation unit m owned by Gi, and the performance payment method $\phi_{i,j,m}$ for $\text{SC}_{i,j,m}$ could be a down/up energy price ($/MWh) given by the expected next-day marginal dispatch cost for unit m.

ISO Portfolio (ISOPort) form:

$$\text{ISOPort} = \{\text{GenPort}_1, \text{GenPort}_2, \text{GenPort}_3\}\,, \tag{2}$$

where no procurement from a GenCo Gi (GenPort$_i$=None) is possible.

3.3 RTM Supply Offer Specifications

A GenCo's RTM supply offer is a collection of GenPorts together with associated GenPort offer prices. Suppose each GenCo offers up-energy in firm contract form, ie, exercise time t_{ex} = t_{ex}^{min} = t_{ex}^{max} = RTM end-time. Suppressing location (k), direction (up), the exercise time t_{ex}, and measurement units from SC representations for ease of exposition, the RTM supply offers of GenCos G1, G2, and G3 are assumed to take the following form:

G1's supply offer consists of two GenPorts, each with one SC:

$$\text{GenPort}_{1,1} = \{\text{SC}_{1,1}\} \text{ at offer price } \text{v}_{1,1}, \tag{3}$$
$$\text{SC}_{1,1} = [t_{pb} = 0,\ t_{pe} = 60,\ |r| \leq 100,\ 0 \leq p \leq 500,\ \phi = 100]$$

$$\text{GenPort}_{1,2} = \{\text{SC}_{1,2}\} \text{ at offer price } \text{v}_{1,2}, \tag{4}$$
$$\text{SC}_{1,2} = [t_{pb} = 0,\ t_{pe} = 60,\ |r| \leq 120,\ 0 \leq p \leq 500,\ \phi = 105].$$

G2's supply offer consists of three GenPorts with multiple SCs:

$$\text{GenPort}_{2,1} = \{\text{SC}_{2,1,1}, \text{SC}_{2,1,2}\} \text{ at offer price } \text{v}_{2,1}, \tag{5}$$
$$\text{SC}_{2,1,1} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 200,\ 0 \leq p \leq 600,\ \phi = 135]$$
$$\text{SC}_{2,1,2} = [t_{pb} = 30,\ t_{pe} = 60,\ |r| \leq 200,\ 0 \leq p \leq 600,\ \phi = 130]$$

$$\text{GenPort}_{2,2} = \{\text{SC}_{2,2,1}, \text{SC}_{2,2,2}, \text{SC}_{2,2,3}\} \text{ at offer price } \text{v}_{2,2}, \tag{6}$$
$$\text{SC}_{2,2,1} = [t_{pb} = 0,\ t_{pe} = 10,\ |r| \leq 100,\ 0 \leq p \leq 100, \phi = 105]$$
$$\text{SC}_{2,2,2} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 200,\ 0 \leq p \leq 600, \phi = 135]$$
$$\text{SC}_{2,2,3} = [t_{pb} = 30,\ t_{pe} = 60,\ |r| \leq 200,\ 0 \leq p \leq 600, \phi = 130]$$

$$\text{GenPort}_{2,3} = \{\text{SC}_{2,3,1}, \text{SC}_{2,3,2}, \text{SC}_{2,3,3}\} \text{ at offer price } \text{v}_{2,3}, \tag{7}$$
$$\text{SC}_{2,3,1} = [t_{pb} = 0,\ t_{pe} = 10,\ |r| \leq 100,\ 0 \leq p \leq 100,\ \phi = 105]$$
$$\text{SC}_{2,3,2} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 200,\ 0 \leq p \leq 700,\ \phi = 140]$$
$$\text{SC}_{2,3,3} = [t_{pb} = 30,\ t_{pe} = 60,\ |r| \leq 200,\ 0 \leq p \leq 700,\ \phi = 135]$$

G3's supply offer consists of two GenPorts with multiple SCs:

$$\text{GenPort}_{3,1} = \{\text{SC}_{3,1,1}, \text{SC}_{3,1,2}, \text{SC}_{3,1,3}\} \text{ at offer price } \text{v}_{3,1}, \tag{8}$$
$$\text{SC}_{3,1,1} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 300,\ 0 \leq p \leq 900,\ \phi = 175]$$
$$\text{SC}_{3,1,2} = [t_{pb} = 33,\ t_{pe} = 39,\ |r| \leq 200,\ 0 \leq p \leq 400,\ \phi = 155]$$
$$\text{SC}_{3,1,3} = [t_{pb} = 48,\ t_{pe} = 54,\ |r| \leq 200,\ 0 \leq p \leq 400,\ \phi = 155]$$
$$\text{GenPort}_{3,2} = \{\text{SC}_{3,2,1}, \text{SC}_{3,2,2}, \text{SC}_{3,2,3}\} \text{ at offer price } \text{v}_{3,2}, \tag{9}$$
$$\text{SC}_{3,2,1} = [t_{pb} = 10,\ t_{pe} = 20,\ |r| \leq 300,\ 0 \leq p \leq 900,\ \phi = 175]$$
$$\text{SC}_{3,2,2} = [t_{pb} = 30,\ t_{pe} = 39,\ |r| \leq 200,\ 0 \leq p \leq 400,\ \phi = 150]$$
$$\text{SC}_{3,2,3} = [t_{pb} = 44,\ t_{pe} = 54,\ |r| \leq 200,\ 0 \leq p \leq 400,\ \phi = 150]$$

3.4 Power-Balance Constraints for ISOPorts

Any ISOPort cleared by the ISO in the RTM must permit the achievement of a *Zero Balance Gap (ZBG)*, ie, an exact balancing of RTM-cleared generation against the ISO's forecasted hour-H net load profile in Fig. 4. As demonstrated in Heo and Tesfatsion (2015), each of the following three ISOPorts enables the achievement of a ZBG:

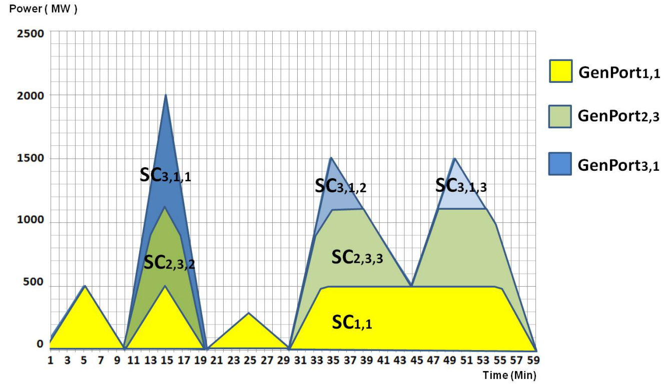
$$\text{ISOPort}_1 = \{\text{GenPort}_{1,1}, \text{GenPort}_{2,2}, \text{GenPort}_{3,1}\} \tag{10}$$
$$\text{ISOPort}_2 = \{\text{GenPort}_{1,1}, \text{GenPort}_{2,3}, \text{GenPort}_{3,1}\} \tag{11}$$
$$\text{ISOPort}_3 = \{\text{GenPort}_{1,2}, \text{GenPort}_{2,3}, \text{GenPort}_{3,2}\} \tag{12}$$

For example, the achievement of a ZBG by ISOPort$_2$ in (11) is depicted in Fig. 5. Each color in Fig. 5 indicates the dispatch of generation from a particular GenPort for a particular GenCo, and different shades of the same color indicate the dispatch of generation from distinct SCs within a particular GenPort.

3.5 Expected Total Cost of a Power-Balanced ISOPort

Consider any ISOPort=(GenPort$_1$,GenPort$_2$,GenPort$_3$) that achieves a ZBG for hour H. The expected total cost of this ISOPort is the sum of payments arising from two sources: (i) the portfolio offer prices $\{v_1, v_2, v_3\}$ that must be paid

Figure 5: Zero balance gap achieved by ISOPort_2 for hour H of day D



to GenCos G1, G2, and G3 for the procurement of GenPort_1, GenPort_2, and GenPort_3; and (ii) the total performance payments the ISO expects it will have to make to G1, G2, and G3 for down/up energy delivery during hour H under the contractual terms of these constituent GenPorts in order to achieve the ZBG.

For example, to calculate the expected total performance payments (ii) implied by the ZBG implementation of ISOPort_2 depicted in Fig. 5, first measure the energy (MWh) for each of the areas in Fig. 5 with a distinct color shading; each such area corresponds to a distinct SC implementation. Next, multiply each of these energy amounts by the performance price ϕ (\$/MWh) included among the contractual terms of the corresponding SC. Finally, add up all of these amounts.

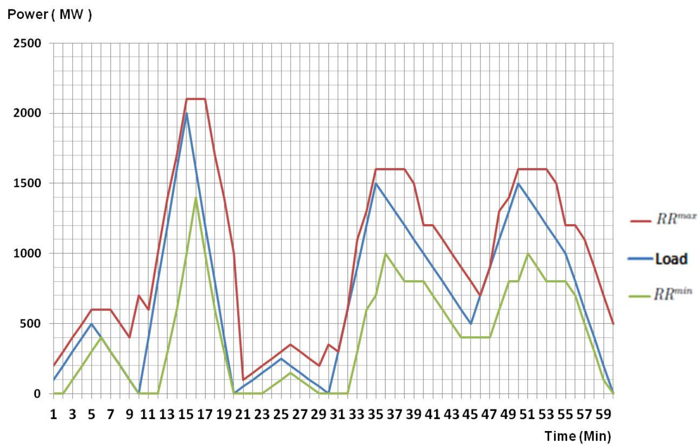
3.6 Reserve Inherent in a Power-Balanced ISOPort

The achievement of a ZBG by an ISOPort implies that the generation available through this ISOPort is capable of balancing the ISO's *forecasted* hour-H net load profile. However, if the SCs constituting this ISOPort include swing, then the ISOPort can also achieve a ZBG for a range of hour-H net load profiles that deviate from the ISO's forecasted hour-H net load profile. Hereafter, this range will be referred to as the *Reserve Range (RR)* of the ZBG ISOPort.

The RR of a ZBG ISOPort with swing in its contractual terms is a robust-control device for ensuring net load balancing, eliminating the need for the ISO to consider detailed net load scenarios and scenario probabilities. However, its exact form depends in a complicated manner on the particular attribute specifications of the SCs that constitute the ISOPort as well as on the minute-by-minute operating state of the *GenCo suppliers*, ie, the GenCos that have offered these SCs. Consequently, in any practical application the RR will have to be approximated.

For example, Fig. 6 plots an approximate RR for ISOPort_2 in (11) obtained by assuming that the GenCo suppliers at the start of each minute M are at their ZBG-generation levels; see Heo and Tesfatsion (2015, Section 3.6) for a detailed derivation. The depicted approximate RR is conditional on the ISO's forecasted hour-H net load profile shown in Fig. 4 and on the ISO's hour-H ZBG implementation for ISOPort_2 shown in Fig. 5.

Figure 6: Reserve range RR for ISOPort_2 during hour H of day D



3.7 Practical Determination of Optimal ISOPorts

Let $\mathcal{L} = \{\text{L}_M \mid 1 \leq \text{M} \leq 60\}$ denote the ISO-forecasted aggregate net load profile for hour H depicted in Fig. 4, expressed at the granularity of minutes M. Suppose the ISO's system-wide requirements for down/up reserve during H can be expressed in terms of the following restrictions on the lower and upper bounds of the reserve range RR corresponding to any ZBG ISOPort cleared to balance $\mathcal{L}$, where $\boldsymbol{\alpha}^* = (\alpha^{D*}, \alpha^{U*}) \geq 0$: For each minute M of hour H,

$$\text{RR}_M^{min} \leq [1 - \alpha^{D*}]\text{L}_M \leq [1 + \alpha^{U*}]\text{L}_M \leq \text{RR}_M^{max} \quad (13)$$

Suppose at least one feasible ISOPort achieves a ZBG for H. Then, as detailed in Heo and Tesfatsion (2015, Section 3.7), the ISO can formulate its RTM optimization problem as a multi-criteria optimization problem with three lexicographically-ordered objectives: (i) ensure a ZBG; (ii) ensure system-wide RR reliability at level $\boldsymbol{\alpha}^*$, ie, satisfy condition (13) for the aggregate net load profile $\mathcal{L}$; and (iii) minimize the expected total cost of ensuring (i) and (ii).

3.8 Incorporation of Transmission-Line Limits

Until now, our RTM illustrative example has assumed an absence of transmission congestion. This simplification has permitted us to focus solely on the economic dispatch problem of ensuring a balance between aggregate dispatched generation and ISO-forecasted aggregate net load, subject to a system-wide RR_{α^*} constraint (13).

In Heo and Tesfatsion (2015, Section 3.8) we extend this RTM example to permit congested transmission lines. To ensure reliability, we assume the ISO imposes a ZBG constraint at each bus, referred to as a *local* ZBG constraint.[5] We also assume the ISO imposes a reserve-requirement constraint (13) at each bus, conditional on the ISO's forecasted net load for that bus, referred to as a *local* RR_{α^*} constraint.[6] We then consider how the ISO would conduct a bid/offer-based RTM SCED optimization subject to constraints that include local ZBG and reserve-requirement constraints at each bus.

4 Linkages between the RTM and the DAM

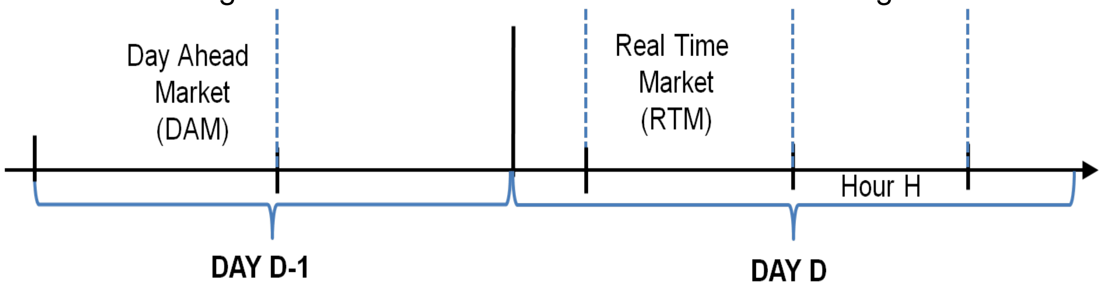
The operations of an RTM that supports SC trading for a particular hour H in the absence of a previously accumulated SC inventory were illustrated in Section 3. In this section we consider an extension of this RTM example in which

[5]Ignoring losses, the local ZBG constraint at each bus k is an equation ensuring that the total power injected at bus k equals the total power withdrawn at bus k plus the total power flowing out from bus k to other buses.

[6]In practice, local reserve-requirement constraints are imposed at the level of reserve zones. In Heo and Tesfatsion (2015) reserve zones are assumed to consist of singleton buses for ease of exposition.

the operations of the RTM are conditioned on an SC inventory acquired in the prior operations of a DAM, as depicted in Fig. 7. The operations of this DAM are assumed to be in accordance with the general DAM description provided in Section 2.3.

Figure 7: Illustrative time-line for DAM/RTM linkages



A key distinction between the DAM on day D-1 and the RTM on day D is that the DAM power-balance constraints are based on LSE demand bids, not on the ISO's own forecasts for LSE-customer loads. Nevertheless, the ISO has a fiduciary responsibility to balance *actual* real-time net loads to ensure grid reliability.

Consequently, we assume the ISO is permitted to bid for SCs in the DAM on day D-1 to ensure that reserve-requirement constraints are met, where these constraints are informed by the ISO's own next-day net load forecasts.[7] The ISO then matches and clears DAM-submitted SC bids and offers to achieve a least-cost ZBG subject to system and reserve-requirement constraints. The ISO subsequently enters into the RTM on day D with a record of all DAM-cleared SCs and conducts RTM operations conditional on this SC inventory.

In Heo and Tesfatsion (2015, Sections 4.1-4.2) we discuss at length, with illustrative examples, how RTM operations for hour H are affected by SC inventory conditioning when reserve-requirement constraints are imposed entirely for regulation (load-balancing) purposes. In Heo and Tesfatsion (2015, Section 4.3) we consider this same issue for an augmented set of reserve-requirement constraints that includes constraints for contingency reserve.

[7]As in Section 2.3, we require all costs arising from the ISO's DAM SC procurement to be charged to market participants in order to preserve the ISO's non-profit status.

5 Discussion

5.1 Comparison with Real-World TSO/ISO Operations

Our ISO-managed DAM/RTM design for the support of SC trading is structurally similar to existing European and U.S. wholesale power market designs. European wholesale power markets include “spot” (day-ahead) and intraday markets for energy and reserve managed by TSOs operating on a non-profit-making basis (ENTSO-E 2015; EPEX 2015). U.S. wholesale power markets include day-ahead and real-time markets for energy and reserve managed by non-profit ISOs (EIA 2015; Heo and Tesfatsion 2015, Table 1).

Moreover, the idea of permitting resources to offer options into TSO/ISO-managed wholesale power markets is not new. For example, Moriarty and Palczewski (2014) demonstrate how a small electricity storage unit could advantageously be permitted to offer American call options into a centrally-managed real-time imbalance market to facilitate load balancing.

On the other hand, our SC system differs sharply from current TSO/ISO operations in other regards. SCs with swing function as intrinsically combined energy and reserve products permitting the provision of a wide range of flexibly-provided services. Also, rewards and penalties can be included in SC performance payment methods to encourage good service performance, eg, accurate load forecasting and/or accurate following of dispatch instructions, where the rewards and penalties are assessed ex post based on actual performance. This inclusion could be required at the SC system level. Alternatively, SC suppliers could voluntarily undertake this inclusion as a way to signal the quality of their offered services to potential SC buyers.

Moreover, our SC system functions as a two-part pricing system under which all payments are compensations for value rendered, with no additional market or out-of-market payment adjustments required. Service *availability* compensation (in the form of SC offer-price payments) becomes obligatory at the commencement of service availability, ie, as soon as SC supply offers are cleared. In contrast, service *performance* compensation (through SC performance payment methods) does not become obligatory until services have been performed in real time.

This two-part pricing system contrasts sharply with the Locational Marginal Pricing (LMP) systems currently implemented in U.S. ISO-managed wholesale power markets. Schweppe et al (1988) conceptualized LMPs for *true* spot markets in which there is no separation in time between payment and delivery, not for forward markets such as DAMs and RTMs. Currently, DAM LMP payment commitments are made in advance for the anticipated real-time dispatch of DAM-cleared generation, that is, in advance of value received. They are then subsequently adjusted through RTM LMP payments to account for any deviations between DAM and RTM scheduled dispatch levels.

Moreover, DAM/RTM LMP payments do not necessarily provide adequate compensation for the costs incurred by resources to provide service availability. The perceived need to cover such costs more fully has led to the institution of capacity markets and various out-of-market uplift payments.

5.2 Comparison with Existing Standardized Power Contracts

The restructuring of European and U.S. electricity sectors, together with their increased reliance on VER generation, has resulted in increased price and volume risks for utilities and independent power producers as prices and net loads have become more volatile and difficult to forecast (Lemming 2004). Financial and physical instruments are now heavily traded in Europe and the U.S. on exchanges and in over-the-counter markets as a means for hedging exposure to these risks (Äid 2015, Deng and Oren 2006, EEX 2015, NYMEX 2015).

In Europe, standardized power contracts have been developed by the Agency for the Cooperation of Energy Regulators (ACER 2014). In the U.S., standardized power contracts have been developed by the Edison Electric Institute and the Western Systems Power Pool (EEI 2014; WSPP 2014). These widely used contracts are negotiated bilateral contracts between two counterparties.

Our proposed standardized contracts (SCs) differ in three important ways from ACER, EEI, and WSPP contracts. First, SCs are bids/offers for submission to an ISO-managed wholesale power market for possible clearing against other submitted offers/bids. In contrast, an ACER, EEI, or WSPP contract is a private agreement between two counterparties; it is subsequently self-scheduled in a TSO/ISO-managed wholesale power market only if fulfillment of the terms of the contract requires the use of power transmission lines.

Second, although the services provided through the contractual terms of SCs can cover the full range of product attributes included in ACER, EEI, and WSPP contracts, SC services are not rigidly separated into product types (capacity, reserve, and energy). Rather, SC services can be used to fulfill capacity requirements (general availability), reserve requirements (designated availability), and/or energy requirements (scheduled real-time dispatch) as appropriate.

Third, SCs permit swing (flexibility) in all of the services included in their contractual terms. In contrast, swing in ACER, EEI, and WSPP contracts is limited to option exercise dates in contracts taking an option form (ACER 2014, Table 1, L 363/131; EEI 2014; WSPP 2014).

5.3 Discriminatory vs. Uniform Pricing of Contracts

A market is said to exhibit *market efficiency* if the total net surplus extracted from the market by the market participants is at a maximum. Total net surplus is measured in practice as the sum of the differences between the buyers' maximum willingness to pay and the sellers' minimum acceptable payment for each successively traded commodity unit; see Stoft (2002) and Tesfatsion (2009).

In order for market efficiency to hold, all valued attributes of a market-traded commodity must be properly priced and compensated at the margin. In a day-ahead energy market organized as a bid/offer (double) auction, market efficiency can be achieved by means of a locally uniform pricing mechanism that assigns the same price to all energy units (MWh) being traded at a particular location for delivery at this location at a particular later time; see Tesfatsion (2009) and Li and Tesfatsion (2011). This is because the units of the traded product, characterized by physical type (energy), delivery location, and delivery time, are homogeneous.

However, a uniform pricing mechanism applied to a traded product does not necessarily result in market efficiency if the units of this product are not homogeneous. In particular, in a market for which buyers and sellers are submitting bids and offers for differentiated products – referred to as a *monopolistically competitive market* within economics – the buyers and sellers must be permitted to bid and offer differentiated prices for units of these differentiated products in order for these prices to reflect the true value of these units to buyers and sellers at the margin, a necessary prerequisite for market efficiency.

As discussed in previous sections, the SCs traded in our proposed DAM and RTM can be highly differentiated products. First, SCs can differ in terms of the types of services they offer. Second, even if two SCs offer the same types of services, the two SCs can differ in terms of the amount of swing included in the specification of these services. Consequently, our DAM and RTM are monopolistically competitive markets. The most appropriate pricing mechanism for SCs in our DAM and RTM is thus a discriminatory pricing mechanism in which SC sellers are permitted to offer differentiated prices for the sale of their differentiated products and SC buyers are permitted to bid differentiated prices for the purchase of these differentiated products.

5.4 Comparison with Existing VER Initiatives

A major development in European and U.S. TSO/ISO-managed wholesale power markets is that increased VER penetration is increasing the volatility of net load (ie, load minus as-available generation). Some TSOs/ISOs are revising their market rules and product definitions to accommodate this development.

For example, as discussed by Navid and Rosenwald (2013) and Xu and Tretheway (2014), MISO and CAISO have each proposed the introduction of "flexible ramping" products. Also, as discussed by Seliga et al (2013), ISO-NE has introduced a major rule change called "Energy Market Offer Flexibility." In addition, some ISOs are exploring innovative ways to incorporate VERs more fully into DAM/RTM operations. For example, MISO has introduced a new resource category called Dispatchable Intermittent Resource (DIR), designed primarily for its wind resources (MISO 2011).

Our proposed SC system is not in conflict with the above market developments. To the contrary, as detailed in previous sections, SC trading would provide additional types of flexibility to both market participants and system operators that complement and extend these developments.

5.5 Robust-Control Management of Uncertain Net Load

A key requirement of standard two-stage stochastic SCUC formulations is the need to specify probability-weighted load scenarios with sufficient accuracy that a switch from currently-used deterministic SCUC formulations can be justified in terms of improved performance. For example, as shown in Krishnamurthy et al (2015, Section V), given a simulated "true" load distribution and an approximate set $\mathcal{S}$ of load scenarios, a deterministic SCUC formulation can result in lower energy costs than a stochastic SCUC formulation based on $\mathcal{S}$ if reserve requirements for the former are set within a "sweet spot" range of values.

The rapidly growing reliance on VERs, resulting in increased net load uncertainty and volatility, has encouraged efforts to develop improved stochastic SCUC formulations based on *net* load scenarios. See, for example, Morales et al (2009), Papavasiliou et al (2011), and Vrakopoulou et al (2013). However, these approaches rely on having an accurate modeling of the stochastic behavior of *net* load, a goal that has not yet been attained for as-available generation such as wind and solar power. In addition, to ensure tractability, they require the application of scenario reduction techniques capable of retaining the essential features of the net load scenarios derived from the original stochastic net load modeling.

Our proposed SC system offers an alternative robust-control approach to the management of uncertain net load. As detailed in Section 3, under this system the ISO considers in advance of an operating period how much swing (flexibility) will be needed in cleared SCs to cover a suitably wide corridor around an expected net load profile for this operating period. Consequently, a detailed specification of net load scenarios is not required.

5.6 Amelioration of Merit-Order and Missing-Money Issues

As noted in Section 5.4, centrally-managed wholesale power markets such as MISO are attempting to integrate VERs into the operations of their DAMs by permitting these resources to submit DAM supply offers based on generation forecasts. VERs tend to have relatively low marginal dispatch costs. Hence, increased VER participation tends to decrease the profits of thermal generators by reducing day-ahead energy prices, an outcome referred to in the power systems literature as the *merit-order effect* (Sensfuß et al 2008). On the other hand, increased VER penetration requires an increase in flexibly-controllable generation to handle the resulting increased volatility of net load. Given the current state of electric energy storage development, this increase in flexibly-controllable generation must largely come from thermal generation.

The problem is then as follows. How can an adequate amount of flexibly-controllable thermal generation be ensured for matching the increased volatility of net load resulting from an increased penetration of VERs when the latter penetration reduces thermal generation profits and hence the incentive to invest in and maintain thermal generation?

This problem can be ameliorated by guaranteeing that thermal generators receive full compensation for all of the valuable services they provide, including flexibly-controllable generation. Our SC system permits this full compensation.

Specifically, under our SC system a thermal generator can offer a GenPort (ie, a portfolio of SCs) that accurately expresses the types of services it can provide as well as the degree of flexibility (swing) with which each of these types of services can be provided. The generator should offer this GenPort at a price that fully covers the costs it would incur to ensure the availability of these services, including capital and lost opportunity costs. If the GenPort is cleared, the generator receives an immediate compensation commitment for service availability equal to the GenPort's offer price. The generator also receives ex-post compensation for any real-time services performed under the terms of the GenPort, where this ex-post compensation is determined by the performance payment methods appearing in the SCs that comprise the GenPort.

Another problem arising in centrally-managed wholesale power markets is *missing money*. Cramton and Ockenfels (2012) characterize this problem as follows: "In 'normal' periods, when there is no shortage of capacity, prices are below the level needed to cover operating and capital costs of new capacity, and in scarcity events, prices are unlikely to accurately reflect the scarcity."

For concreteness, our current paper focuses on the support of SC trading through relatively short-horizon DAM and RTM operations. More generally, however, SC trading could be supported by a sequence of linked forward markets that includes longer-term forward markets with planning horizons spanning a year or more. In these longer-term forward markets, the two-part pricing of SCs would permit investors to receive availability and performance payments that fully cover their capital, lost opportunity, and operating costs, thus helping to resolve the missing-money problem.

6 Conclusion: Energy Policy Implications

Key policy implications of our proposed market-supported trading of standardized contracts (SCs) permitting swing (flexibility) in their contractual terms are noted throughout Sections 1 through 5. These policy implications are concisely summarized below:

(i) The SC system permits separate full market-based compensation for service availability and service performance

SCs can function both as standardized instruments for the procurement of service *availability* in forward markets and as standardized blueprints for the procurement of service *performance* in real-time system operations. Thus, SC trading supports the goals of FERC Order 755 (FERC 2011); but this support is for a much broader array of services than envisioned in this order.

ii) The SC system facilitates a level playing field for market participation

The SC system focuses on service provision capability rather than on the physical characteristics of resources. This should permit and encourage the participation of a wider array of resources in wholesale power markets.

(iii) The SC system facilitates co-optimization of energy and reserve markets

SCs with swing intrinsically function as both energy and reserve products, eliminating the need to provide separate eligibility requirements and settlement processes for energy versus reserve services.

(vi) The SC system supports forward-market trading of energy and reserve

The *offer price* of an SC, determined through market processes, compensates the SC issuer for a guarantee of *service availability*. In contrast, the *performance payment method* of an SC, appearing among its contractual terms, determines how the SC issuer is to be compensated ex post for *actual services rendered* in real-time operations.

(iv) The SC system provides a fair way for all potential service providers to offer flexible service availability

SCs with swing permit the *providers* of these contracts to be appropriately compensated for flexibility in offered services, such as offered exercise times, begin-times, end-times, down/up ramp rates, and down/up power levels. Moreover, the ability of one or more resources to offer services in the combined form of an SC portfolio (GenPort) can enhance the ability of resources to obtain appropriate compensation for the full value of their services.

(v) The SC system provides system operators with real-time flexibility in service usage

SCs with swing permit system operators who *procure* these SCs to implement the services offered in these SCs in a flexible manner during real-time operations.

(vii) The SC system encourages accurate load forecasting and the accurate following of real-time dispatch instructions

Rewards and/or penalties can be incorporated into the performance payment methods ϕ appearing among the contractual terms of SC demand bids to encourage LSEs and other wholesale intermediaries who bid for services on behalf of retail customers to submit bids that accurately reflect the service needs of these customers. Similarly, rewards and/or penalties can be incorporated into the performance payment methods ϕ appearing among the contractual terms of SC supply offers to encourage service suppliers to follow real-time service performance instructions with high accuracy.

(viii) The SC system permits resources to internally manage unit commitment and generation-capacity constraints

By offering an SC for a particular operating period, a resource is guaranteeing that it can feasibly perform the services represented in this SC during this period. For generators, this feasibility includes the assurance that power generation units with suitable capacities will be synchronized to the grid as necessary to perform these services.

(ix) The SC system permits robust-control management of uncertain net load

Under the SC system, the ISO considers in advance of an operating period how much swing (flexibility) will be needed in cleared SCs to cover a suitably wide corridor around an expected net load profile for this operating period. The SC system thus provides a robust-control alternative to standard stochastic formulations for SCUC/SCED requiring detailed specifications of net load scenarios and scenario probabilities.

(x) The SC system eliminates the need for out-of-market payment adjustments

SC offer prices for service availability and SC performance payments for service performance provide full compensation for all rendered value, without need for additional market or out-of-market (OOM) payment adjustments.

(xi) The SC system reduces the complexity of market rules

Properties (i)-(x) reduce the complexity of power market rules, hence the opportunity for market participants to game these rules for their own advantage.

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