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New Wholesale Power Market Design Using Linked Forward Markets

A Study for the DOE Energy Storage Systems Program

Leigh S. Tesfatsion, César A. Silva-Monroy, Verne W. Loose, James F. Ellison, Ryan T. Elliott, Raymond H. Byrne, and Ross T. Guttromson

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Abstract

This report proposes a reformulation of U.S. ISO/RTO-managed wholesale electric power markets for improved reliability and efficiency of system operations. Current markets do not specify or compensate primary frequency response. They also unnecessarily limit the participation of new technologies in reserve markets and offer insufficient economic inducements for new capacity investment. In the proposed market reformulation, energy products are represented as physically-covered firm contracts and reserve products as physically-covered call option contracts. Trading of these products is supported by a backbone of linked ISO/RTO-managed forward markets with planning horizons ranging from multiple years to minutes ahead. A principal advantage of this reformulation is that reserve needs can be specified in detail, and resources can offer the services for which they are best suited, without being forced to conform to rigid reserve product definitions. This should improve the business case for electric energy storage and other emerging technologies to provide reserve. In addition, the facilitation of price discovery should help to ensure efficient energy/reserve procurement and adequate levels of new capacity investment.

keywords: Electric Energy Markets, Market Design, Power Systems.

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Executive Summary

Existing U.S. wholesale electric power markets have a number of shortcomings. Key issues are as follows:

1. Primary frequency response, here defined as synchronized reserve capacity that autonomously responds to changes in system frequency, is neither specified nor compensated. In the past, all generation units supplied this service. Wind and solar generation, however, usually do not. If not specified and appropriately compensated, this service might not be adequately supplied in the future.
2. Reserves are segmented into discrete product categories that are variously defined across the different market regions. Some product definitions are presumably more efficient than others. In addition, some system operators are finding that the current product segmentation does not adequately meet their needs. Evidence of this is seen in the recent efforts by several system operators to introduce new reserve product categories.
3. With the exception of regulating reserve, existing reserve markets compensate fast, capacity-constrained resources the same as slow, ramp-rate-constrained resources. This discourages the entrance of fast, capacity-constrained resources. It also limits the ability of a system operator to secure reserve resources based on the response characteristics of these resources.
4. The bulk of energy and reserve products in the U.S. are currently traded through privately negotiated bilateral contracts. The resulting lack of transparency hinders price discovery and efficient trading.
5. Sufficient levels of new resource capacity are not being built in these markets, which are generally short-term in nature. Having some form of long-term revenue certainty would greatly facilitate the financing of new projects.

Rather than addressing these shortcomings through incremental changes, we believe there is value in considering a new market design. The two key innovations of this design are: (i) the introduction of standardized contracts for energy and reserve; and (ii) the introduction of a sequence of linked centrally-managed forward markets that support the trading of these standardized contracts, with planning horizons ranging from multiple years to minutes ahead.

Energy products are represented as physically covered firm contracts, and reserve products are represented as physically covered call option contracts. This contract representation permits the elimination of discrete reserve product categories based on resource characteristics and instead permits energy and reserve products to be specified and compensated on the basis of their performed services.

The new market design also provides for a sequence of linked long-term and short-term forward markets through which these standardized energy/reserve contracts can be bought and sold. Each forward market is organized as an exchange centrally managed by a non-profit system operator, and is designed to facilitate resource procurement for a future real-time operating period. Each market thus marks a waypoint along the timeline approaching this real-time operating period, with each successive market offering an updated and more refined picture of the load, and of what changes to the scheduled resource mix are needed to meet this load.

Private profit-seeking traders can participate in these linked forward markets by submitting supply offers for energy and reserve contracts as well as demand bids for energy contracts. They can also self-schedule in these markets the energy outcomes of privately negotiated physical bilateral trades, and they can engage in financial contracting outside of these markets to hedge their price risks.

The system operator participates in these linked forward markets in two ways. First, it can submit demand bids for reserve contracts in accordance with perceived system reliability needs. Second, it matches contract supplies with contract demands in merit order subject to system constraints, taking into account linkages with preceding and/or subsequent forward markets. These linkages permit the portfolio of contracts relevant for each future operating period to be continually adjusted in each successive forward market, leading ultimately to the deployment of these contracts in the operating period to ensure reliable and efficient system operations.

The key advantages of this new market design are as follows:

1. Level playing-field for reserve providers: Reserve products are characterized in terms of provided services rather than in terms of physical resource characteristics. This permits all resources capable of providing these services to compete freely as reserve providers and to receive compensation based on the value of the services they provide.

2. Greater specificity in reserve requirements leading to more efficient reserve procurement: The introduction of standardized energy/reserve contracts with flexible attributes in place of rigid reserve product categories would permit the system operator to specify reserve requirements with more precision. Reserve procurement should then be more efficient, since it should be possible to assemble a portfolio of resources that better meets these more precisely specified reserve requirements. Another advantage of this approach is that primary frequency response can be explicitly taken into account and thus appropriately compensated.

3. Increased transparency of market operations: The institution of linked forward markets supporting energy/reserve trading in standardized contract form should increase the transparency of market operations and facilitate price discovery. This should help to reduce dependence on privately negotiated bilateral contracts.

4. Market efficiency gains: The establishment of one or more centrally-managed markets for longer-term energy/reserve procurement would provide traders with an alternative to bilateral contract trading. These organized markets should be more efficient than bilateral contracting, since they should provide for better price discovery. Furthermore, the standardization of contracts should reduce transactions costs.

5. Improved incentives for new capacity investment: By improving the efficiency of longer-term trading, the new market design could increase the amount of energy and reserve supplied through longer-term contracts. More longer-term contracting should promote price stability, and could help to insure that market prices compensate resources for both fixed and variable costs. Full compensation of costs would help provide incentives for new resource capacity to enter the market. The more successful longer-term contracting is at achieving full compensation of costs, the less the need for separate capacity markets that aim to achieve the same goal.

Nomenclature

AGC Automatic Generation Control

CAISO California Independent System Operator

DAM Day-Ahead Market

ERCOT Electric Reliability Council of Texas

FC Firm Contract

FERC Federal Energy Regulatory Commission

ISO Independent System Operator

ISO-NE Independent System Operator-New England

LTFM Long-Term Forward Market

MISO Midwest Independent System Operator

NYISO New York Independent System Operator

OC Option Contract

PJM PJM Interconnection

RT Real-Time

RTM Real-Time Market

RTO Regional Transmission Organization

SCED Security Constrained Economic Dispatch

SCUC Security Constrained Unit Commitment

SPP Southwest Power Pool

STFM Short-Term Forward Market

WPM Wholesale Power Market

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1 Introduction

In a series of notices culminating in [1], the U.S. Federal Energy Regulatory Commission (FERC) recommended that U.S. energy regions operate as wholesale electric power markets centrally managed by a non-profit Independent System Operator (ISO) or Regional Transmission Organization (RTO).[1] Six U.S. energy regions are currently operating in accordance with FERC's design: CAISO, ERCOT, ISO-NE, MISO, NYISO, and PJM; and a seventh region (SPP) is planning a 2014 launch of an Integrated Market that conforms to FERC's design.

FERC's market design provides a basic template for the bulk purchase and sale of electrical energy. Building on the seminal work of Schweppe et al. [2,3], the foundation of the template is the concept of an ISO-managed *two-settlement system*. Roughly described, a two-settlement system comprises: (i) a day-ahead market (DAM) for the day-ahead commitment, dispatch, and pricing of generation to meet anticipated next-day loads; and (ii) a real-time market (RTM) for the procurement and pricing of any "imbalance energy" needed to resolve discrepancies between day-ahead dispatch levels and actual real-time loads. The objective of the two-settlement system is to permit the commitment, dispatch, and pricing of energy to be determined by the supplies and demands of sellers and buyers, as in ordinary commodity markets, to an extent consistent with reliable operation of the grid.

On the other hand, FERC's market design does not provide any specific guidance for the provision of reserve[2] to assure adequate resources to meet customers' needs in accordance with NERC standards. Rather, this assurance is explicitly left to the individual states within each energy region [1, p. 11].

Over the past ten years a great deal has been learned about the provision of reserve in support of energy markets. As evidenced in [4] through [37], a large literature has arisen to document and research these lessons. Nevertheless, as detailed in Pfeifenberger et al. [38, Table 1, p. 7], U.S. ISO-managed wholesale power markets have taken widely different approaches to reserve provision. ERCOT is classified as an *energy-only market*, i.e., a market for which resources obtain revenues solely through markets for energy and ancillary services without additional payments for capacity. SPP is classified as an *energy market with reserve requirements*. MISO and NYISO are classified as *energy markets with reserve requirements and centralized capacity markets*. CAISO is classified as an *energy market with forward reserve requirements*.[3] Finally, ISO-NE and PJM are classified as *energy markets with forward reserve requirements and centralized capacity markets*.

This lack of uniformity in reserve provision policies has led to a number of problems. Key issues are as follows:

1. Primary frequency response[4] is neither specified nor compensated in these markets. In the past, all generation units supplied this service. Wind and solar generation, however, usually do not. If not specified and appropriately compensated, this service might not be adequately supplied in the future.

[1] The essential difference between an ISO and an RTO is that RTOs have larger regional scope. Hereafter, to avoid clumsy notation, the system operator will simply be referred to as an ISO.

[2] In this report "energy" is used to refer to the actual production of electrical energy. In contrast, "reserve" is used as short-hand for capacity availability, meaning an amount of up/down generation or demand response that a market participant agrees to provide if signaled by an ISO to do so for system reliability purposes.

[3] A forward reserve requirement is a reserve requirement that is monitored and enforced from one to several years ahead of actual delivery.

[4] In this report we define primary frequency response as synchronized reserve capacity that autonomously responds to changes in system frequency.

2. Reserves are segmented into discrete product categories that are variously defined across the different operating market areas. Some product definitions are presumably more efficient than others. In addition, some ISOs are finding that the current product segmentation does not adequately meet their needs. Evidence of this is seen in the recent efforts by several ISOs to introduce new reserve product categories.

3. In existing reserve markets, fast, capacity-constrained resources are generally compensated the same as slow, ramp-rate-constrained resources.[5] This discourages the entrance of fast capacity-constrained resources. It also limits the ability of an ISO to secure reserve resources based on the response characteristics of these resources.

4. The bulk of energy and reserve products in the U.S. are currently traded through privately negotiated bilateral contracts. The resulting lack of transparency hinders price discovery and efficient trading.

5. Sufficient levels of new generation capacity investment[6] are not being induced in these markets, which are almost exclusively of a short-term nature. Firms deciding whether to invest in new generation capacity need some form of long-term revenue certainty in order to finance new projects.

This report proposes a reformulation of U.S. ISO-managed wholesale electric power markets that addresses these issues. The proposed reformulation builds on the insights of many previous electricity market researchers who have stressed the importance of contracting and risk hedging in advance of real-time operations, most notably the "safe passage" writings by Oren [39,40], but also work by an EPRI research team [41], Hung-Po Chao and Robert Wilson [42], and William Hogan [43].

Our proposed market reformulation can be summarized as follows:

1. All energy and reserve products are represented as standardized contracts taking the form of physically-covered *firm contracts (FCs)* for energy and physically-covered *call option contracts (OCs)* for reserve.

2. FC/OC trading is supported by a sequence of linked forward markets to ensure the efficient procurement of adequate energy and reserve for each operating instant of each operating day.

3. Each forward market is organized as an ISO-managed exchange subject to system constraints.

4. The planning horizon of each forward market can range from multiple years to minutes ahead of an operating instant.

5. Private profit-seeking traders can participate in these linked forward markets by submitting FC/OC supply offers and FC demand bids. They can also self-schedule in these markets the energy outcomes of negotiated physical bilateral trades and engage in financial contracting outside of these markets to hedge their price risks.

6. The system operator participates in these linked forward markets in two ways: (i) Submission of OC demand bids in accordance with perceived system reliability needs; and (ii) clearing

[5]FERC Order 755 was issued to address this issue in reserve markets for regulation (where a resource responds to an Automatic Generation Control signal). This order is being implemented differently by the various ISOs. Other synchronous reserve markets, such as spinning reserve, are not covered by Order 755. Thus, the problem has not been completely resolved.

[6]Here, the term "generation capacity investment" is used broadly, and is not intended to exclude investments in electricity storage or demand-side management. Also, "capacity investment" refers to the investment in physical capacity, and does not imply that a capacity market is required.

of FC/OC supplies and demands in merit order subject to system constraints, taking into account linkages with preceding and/or subsequent forward markets.

7. The linking is achieved by having contracts cleared in earlier trading be carried forward on the books of the ISO as a contract portfolio subject to continual adjustments in each successive forward market.

The advantages of this market reformulation are as follows:

1. Level playing-field for reserve providers: Reserve products are characterized in terms of provided services rather than in terms of physical resource characteristics. This permits all resources capable of providing these services to compete freely as reserve providers and to receive compensation based on the value of the services they provide.

2. Greater specificity in reserve requirements leading to more efficient reserve procurement: The introduction of standardized energy/reserve contracts with flexible attributes in place of rigid reserve product categories would permit the system operator to specify reserve requirements with more precision. Reserve procurement should then be more efficient, since it should be possible to assemble a portfolio of resources that better meets these more precisely specified reserve requirements. Another advantage of this approach is that primary frequency response can be explicitly taken into account and thus appropriately compensated.

3. Increased transparency of market operations: The institution of linked forward markets supporting energy/reserve trading in standardized contract form should increase the transparency of market operations and facilitate price discovery. This should help to reduce dependence on privately negotiated bilateral contracts.

4. Market efficiency gains: The establishment of one or more centrally-managed markets for longer-term energy/reserve procurement would provide traders with an alternative to bilateral contract trading. These organized markets should be more efficient than bilateral contracting, since they should provide for better price discovery. Furthermore, the standardization of contracts should reduce transactions costs.

5. Improved incentives for new capacity investment: By improving the efficiency of longer-term trading, the new market design could increase the amount of energy and reserve supplied through longer-term contracts. More longer-term contracting should promote price stability, and could help to insure that market prices compensate resources for both fixed and variable costs. Full compensation of costs would help provide incentives for new resource capacity to enter the market. The more successful longer-term contracting is at achieving full compensation of costs, the less the need for separate capacity markets that aim to achieve the same goal. Project developers interested in reserve provision can compete for option premiums in long-term forward markets to cover any anticipated future capital costs associated with this reserve provision, thus encouraging new reserve capacity in an economically efficient manner.

Section 2 sets out a number of general market design principles that have guided our search for an improved formulation for U.S. ISO-managed wholesale electric power markets. Quantitative definitions for energy and reserve products as FCs and OCs are developed in Section 3. Our proposed linked market design supporting the trade of FCs/OCs is discussed in greater detail in Section 4, and the deployment of these traded FCs/OCs in real-time operations is discussed in Section 5. Key issues to be addressed in future studies are outlined in the concluding Section 6. Appendix A provides numerical FC/OC examples, Appendix B considers practical implementation aspects for

FCs/OCs, and Appendix C discusses time-domain and frequency-domain representations for real-time reserve requirements.

2 General Market Design Principles

The formulation of the forward markets for energy and reserve developed in subsequent sections of this report has been guided by general market design principles based in part on the design criteria set forth in Oren [39, Section II.A]. Briefly summarized, these principles are as follows:

1. *Achieves Resource Adequacy*
   The market design should provide sufficient incentives for new resources to enter in sufficient quantity to accommodate retirements, de-ratings, and the increase in electricity demand over time while maintaining adequate capacity to provide for contingencies as they occur.

2. *Requires Minimum Administrative Interventions*
   The market should be designed so as to reduce ad hoc rulemaking to the greatest extent possible. This is accomplished primarily through defining market products based on the services required by the system rather than by the technological characteristics of system assets. Whenever possible, mechanisms should be set up to allow and induce transitions to a design with limited administrative control. The market should encourage the participation of both supply and demand resources in system balancing. Efficient resource allocation can be achieved only with activate participation of both supply and demand resources.

3. *Meets Economic Requirements*
   The market design should be efficient, i.e., it should not waste resources. To ensure efficiency, the market design should encourage existing participants to economize on the use of their resources; and it should also encourage the entry of new participants with improved technologies and new kinds of product offerings.

4. *Meets Engineering Requirements*
   The market design should aim to achieve system reliability, ensuring both adequacy and security. System control and balancing must be workable within the context of the market design.

5. *Ensures Open Access for All Resources*
   The market design should be fair, providing an even playing field for market participants. It should permit, indeed encourage, all resources to compete for the provision of energy and reserve products on an even playing field, and it should discourage the exercise of market power.

6. *Has Transparent Operations*
   The market design should be as straightforward and transparent as possible, given economic, engineering, and open access requirements.

7. *Supports Recent Market Reform Efforts*
   The market design should accord with the spirit of recent FERC and ISO initiatives instituting increased market access, pay for performance, demand-side participation, and encouragement of private initiative.

3 Standardized Contracts for Energy and Reserve Products

3.1 Motivation for Contract Standardization

Our linked market design is based on standardized contracts for electrical energy and reserve, referred to as *Wholesale Power Market (WPM) contracts*. These contracts must fulfill two critical roles. First, they must permit the efficient pricing and procurement of energy and reserve in forward markets. Second, they must provide blueprints permitting the physical deployment of energy and reserve in real-time operations to ensure system reliability and efficiency.

Key properties of WPM contracts are developed and illustrated in the following subsections.[7] As will be seen, these contracts share some of the characteristics of standard contracts for storable commodities. However, they also include distinct terms tailored to the needs and requirements of electrical power systems.

3.2 Contract Definitions

A WPM contract refers to two basic types of contracts for electrical energy. The first type of contract, used for energy products, is a physically-covered *firm contract (FC)* for energy procurement. The second type of contract, used for reserve products, is a physically-covered *call option contract (OC)* for energy procurement.

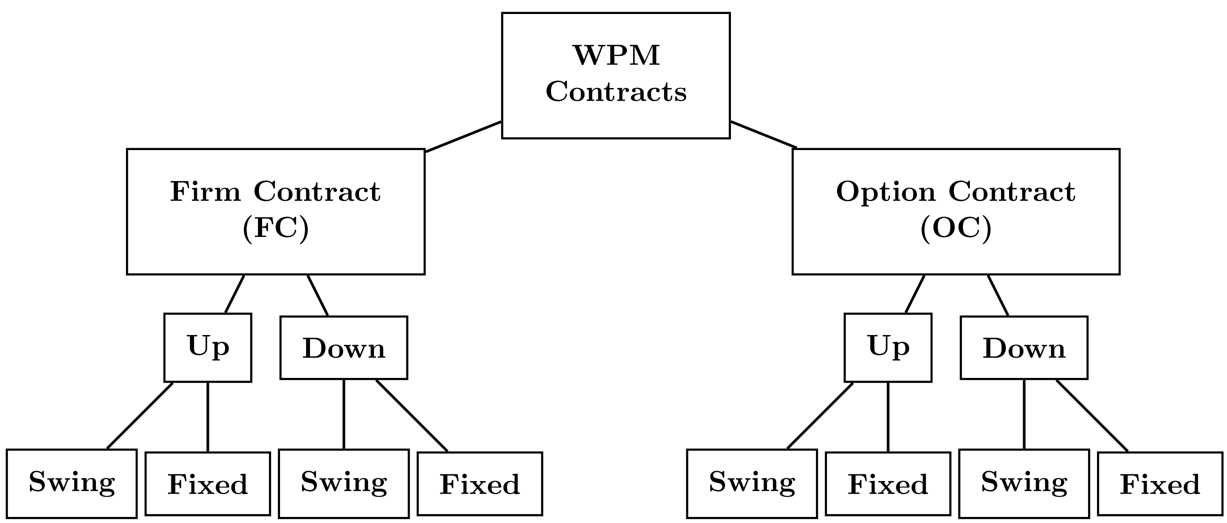

Figure 1: Types of Wholesale Power Market Contracts

Figure 1 depicts our categorization of WPM contracts into FCs and OCs. Each type of contract is assumed to be further differentiated in accordance with the direction of its required power increments. An "up" contract refers either to an increase in generation or to a decrease in load by a demand response resource. A "down" contract refers either to a decrease in generation or to an increase in load by a demand response resource. This sharp division can easily be softened to

[7] Numerical examples are provided in Appendix A.

permit the inclusion of mixed contracts in which contract issuers are called upon both to inject power and to withdraw power during the contract performance period.

In addition, each up/down contract is further subdivided into swing and fixed types. A *swing* contract has one or more of its contractual terms designated as ranges rather than as point values, thus permitting some degree of flexibility in their implementation.[8] Swing contracts are generally intended for the provision of balancing energy by means of resources subject to *automatic generation control (AGC)*, meaning they are able to follow a varying power command signal over a length of time subject to contractually specified amplitude, ramping, and duration limits. In contrast, each contractual term of a *fixed* contract is designated as a point value. Fixed contracts are intended for resources that can be either manually or automatically controlled to generate a near-constant power output for a contractually specified duration (i.e., block energy).

For simplicity of exposition, this report assumes swing (range flexibility) for WPM contracts is restricted to a subset of their contractual terms: namely, the exercise time; the start time; the power increment; the ramp rate; and the stop time. However, it is important to keep in mind that the number of contractual terms embodying swing could easily be broadened to accommodate other system needs such as droop control.

3.3 General Contract Properties

An FC is a non-contingent contract that requires specific performance from both counterparties. It *obligates* the holder to procure up/down power increments from the issuer, and the issuer to deliver these up/down power increments, under contractually specified terms.[9] In contrast, an OC gives the holder the right, but not the obligation, to procure up/down power increments from the issuer under contractually specified terms.

The procurement payment for an FC is the amount that the holder pays to procure the contracted amount of up/down power under the stated contractual terms. This procurement payment can be settled at the time of contract procurement, after the terms of the contract are fulfilled, or in one or more payments made at scheduled times between procurement and contract fulfillment.

The procurement payment (or "premium") of an OC is the amount that the holder pays to procure the insurance value of the OC, which is positive whether or not the holder subsequently exercises the contract. More precisely, the premium compensates the issuer for agreeing to maintain the availability of generation capacity or load flexibility for possible later provision of up/down power. This compensation would typically have to cover two types of costs in order for the issuer to agree to sell the option: (i) costs directly incurred by the issuer to maintain the required availability of generation capacity or load flexibility, such as mortgage payments for power plant capacity; and (ii) opportunity costs incurred by the issuer, such as lost profits from the inability to use the set-aside generation capacity for energy production.

[8] See [15, Section 2.2.4] for a discussion of various types of swing options that have been designed for standard commodities.

[9] A newly issued contract bought and sold in a primary market imposes requirements on both the contract issuer (seller) and the contract holder (buyer). If the contract holder then resells this contract in a secondary market, its duties under this contract are transferred to the new contract holder; however, the duties imposed on the initial contract issuer are generally unaffected by this contract ownership change. To handle both newly issued contracts and contracts that have been resold in secondary markets, this report refers to contract issuers and (current) contract holders rather than to contract sellers and buyers.

If the holder of an OC subsequently exercises the option, the holder is further required to make a performance payment to the issuer in accordance with the performance payment method appearing as one of the contractual terms of the OC. This performance payment can play multiple roles depending on the exact form it takes.

For example, in traditional commodity options the performance payment often takes the form of a pre-specified "exercise price" (or "strike price") for a delivered commodity. A pre-specified exercise price eliminates price risk for the option holder; it ensures the holder that the contractually specified amount of delivered commodity can be obtained at a price no greater than the exercise price. Conversely, a pre-specified exercise price can be used to assure the option issuer that, should the option be exercised, the costs of providing the contractually specified amount of delivered commodity will be fully compensated. However, the performance payment method could also be used to protect the holder and issuer against other types of risks or contingencies arising after the exercise of the option, such as unexpectedly volatile real-time conditions.[10]

The following section develops quantitative representations for two polar contract forms: namely, a fixed FC and a swing OC. Quantitative representations for intermediate contract forms, such as FCs with swing or OCs with fixed terms, can easily be formulated by appropriate modifications of these two polar forms.

3.4 Quantitative Contract Representations

3.4.1 Fixed FCs

Our general quantitative representation for a fixed FC is as follows:

$$\text{fixed FC} = f(k, \text{direction}, r_{SU}, t_{PStart}, p, t_{PStop}) \tag{1}$$

where:

$$\begin{aligned}
k &= \text{Location where up/down power delivery is to occur} && (2)\\
\text{direction} &= \text{Up or down} && (3)\\
r_{SU} &= \text{Start-up ramp rate (MW/minute)} && (4)\\
t_{PStart} &= \text{Power start time} && (5)\\
p &= \text{Power increment (MW)} && (6)\\
t_{PStop} &= \text{Power stop time} && (7)
\end{aligned}$$

As illustrated in part (a) of Fig. 2, the holder of the fixed FC (1) must take delivery from the contract issuer of the up/down power increment p at location k starting at time t_{PStart} and stopping at time t_{PStop}. The power start and stop times t_{PStart} and t_{PStop} denote specific calendar times expressed at the granularity of minutes, e.g., dd-mm-yyyy HH:MM. The start-up ramp rate r_{SU} and the power increment p are assumed to be strictly positive. The direction (up or down) determines whether r_{SU} and p describe a power injection (up) or a power curtailment or absorption (down).

[10] Although unsatisfactory performance by option counterparties could be penalized through the specification of option performance payment methods, it might make option contracts very intricate and thus more difficult to price. In this report we instead assume that performance penalties are handled by means of ISO-determined market-wide rules.

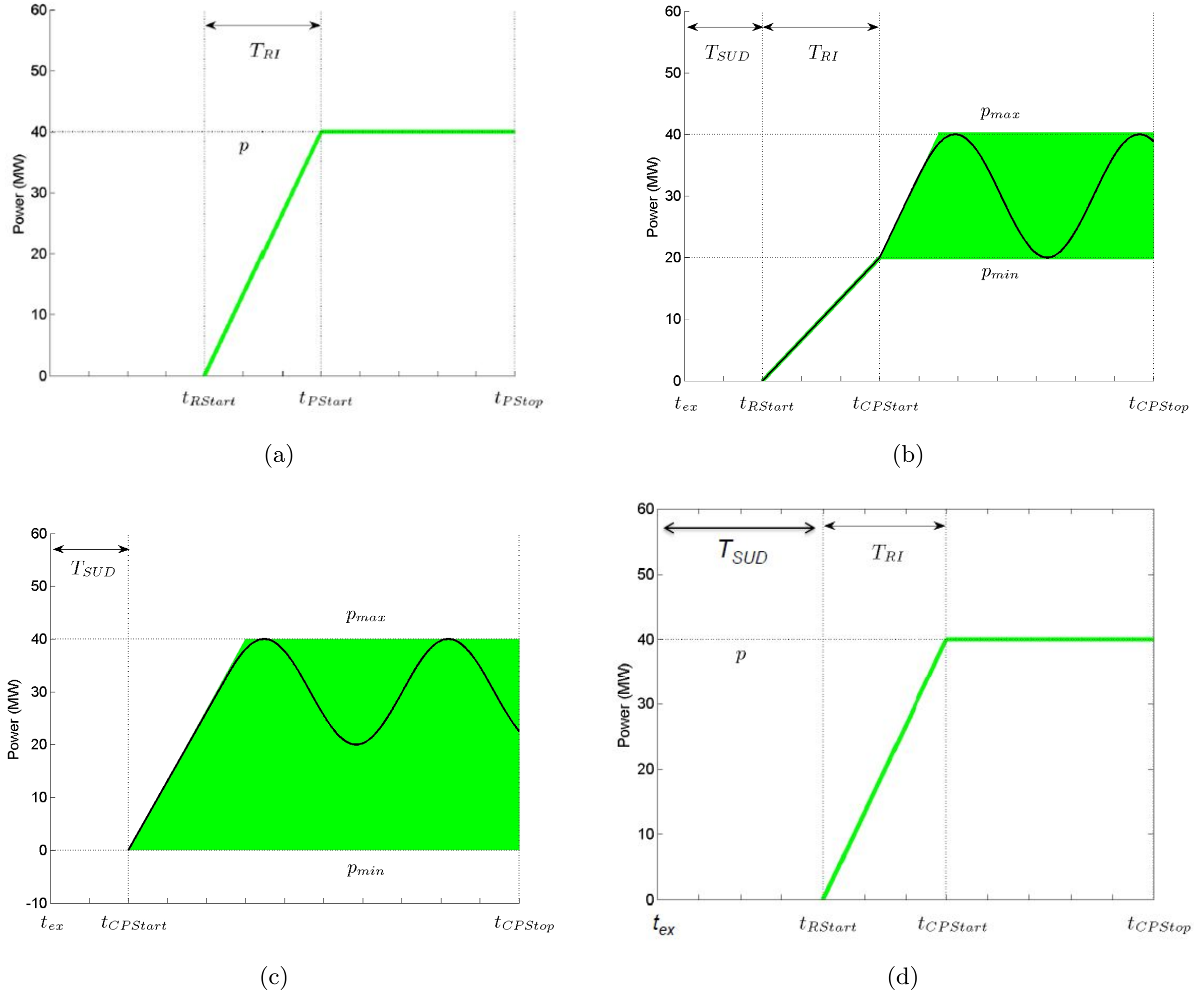

Figure 2: Illustrations of WPM contracts in both FC and OC form. Part (a): Illustration of a fixed FC in the up direction. Part (b): Illustration of an OC in the up direction allowing swing in the controlled power increment p, with $p_{min} > 0$, and in the controlled ramp rate r. Part (c): Illustration of an OC in the up direction allowing swing in the controlled power increment p, with $p_{min} = 0$, and in the controlled ramp rate r. Part (d): Illustration of a fixed OC in the up direction with fixed $p > 0$ and fixed $r = 0$.

For later purposes, it is useful to derive additional characteristics of the fixed FC (1). Given the start-up ramp rate r_{SU}, the power start time t_{PStart}, and the required power increment p, the needed *ramp start time* t_{RStart} can be derived from

$$r_{SU} \times [t_{PStart} - t_{RStart}] \;=\; p \tag{8}$$

Note that the assumed positivity of r_{SU} and p imply that

$$t_{RStart} \;<\; t_{PStart} \tag{9}$$

The *ramping interval* T_{RI} can then be defined as

$$T_{RI} \;\;=\;\; [t_{RStart}, t_{PStart}] \tag{10}$$

Given the power start and stop times t_{PStart} and t_{PStop}, the *duration* d (in minutes) can be derived as

$$d \;=\; [t_{PStop} - t_{PStart}] \tag{11}$$

The total up/down energy delivered under the contractual terms of a fixed FC (1) can be measured, ex post, by

$$e^{FC}_{tot} \;=\; \left[\int_{t_{RStart}}^{t_{PStart}} p(t)dt\right] \;+\; \left[\int_{t_{PStart}}^{t_{PStop}} p(t)dt\right], \tag{12}$$

where $p(t)$ denotes the actual up/down power increment delivered by the FC issuer at time t. The procurement price paid for a fixed FC will presumably have to compensate the FC issuer for the total up/down energy procured over the interval $[t_{PStart}, t_{PStop}]$. Whether the procurement price also compensates the FC issuer for the energy expended over the ramping interval $T_{RI} = [t_{Rstart}, t_{PStart}]$ could depend on the extent to which this ramping energy is viewed as valuable or undesirable by potential FC buyers.

3.4.2 Swing OCs

Our general quantitative representation for a swing OC is as follows:

$$\text{swing OC} = f(k, \text{direction}, r_{SU}, T_{ex}, T_{CPStart}, P_C, R_C, T_{CPStop}, e_{cap}, \phi\text{-method}) \tag{13}$$

where:

$$\begin{aligned}
k &= \text{Location where up/down power delivery is to occur} && (14)\\
\text{direction} &= \text{Up or down} && (15)\\
r_{SU} &= \text{Start-up ramp rate (MW/minute)} && (16)\\
T_{ex} &= \text{Set of possible contract exercise times } t_{ex} && (17)\\
T_{CPStart} &= \text{Set of possible controlled power start times } t_{CPStart} && (18)\\
P_C &= \text{Interval } [p_{min}, p_{max}] \text{ of possible controlled power increments } p \text{ (MW)} && (19)\\
R_C &= \text{Interval } [-r_{min}, r_{max}] \text{ of possible controlled ramp rates } r \text{ (MW/minute)} && (20)\\
T_{CPStop} &= \text{Set of possible controlled power stop times } t_{CPStop} && (21)\\
e_{cap} &= \text{Available energy capacity (MWh)} && (22)\\
\phi\text{-method} &= \text{Performance payment method for services performed after contract exercise} && (23)
\end{aligned}$$

The time points t_{ex}, $t_{CPStart}$, and t_{CPStop} in (17),(18), and (21) denote specific calendar times expressed at the granularity of minutes, e.g., dd-mm-yyyy HH:MM. The start-up ramp rate r_{SU} is assumed to be strictly positive. The limits for the interval P_C of possible controlled power increments are assumed to satisfy $0 \leq p_{min} < p_{max}$. The direction (up or down) determines whether the start-up ramp rate and power increments describe power injection (up) or power curtailment or absorption (down). The limits for the interval R_C of possible controlled ramp rates are assumed to satisfy $-r_{min} \leq 0 \leq r_{max}$ for some nonnegative values r_{min} and r_{max}.

Given any specific controlled power start time $t_{CPStart}$ in $T_{CPStart}$, the corresponding *ramp start time* t_{RStart} can be determined from

$$r_{SU} \times [t_{CPStart} - t_{RStart}] \;=\; p_{min} \tag{24}$$

The ramp start time is the time point at which the OC issuer would need to start ramping up (or down) its power from a synchronized state in order to be able to achieve the up/down power increment p_{min} by time $t_{CPStart}$. Note that

$$t_{Rstart} = t_{CPStart} \quad \text{if and only if} \quad p_{min} = 0 \tag{25}$$

$$t_{Rstart} < t_{CPStart} \quad \text{if and only if} \quad p_{min} > 0 \tag{26}$$

If $p_{min} > 0$, the *ramping interval*

$$T_{RI} \quad = \quad [t_{RStart}, t_{CPStart}] \tag{27}$$

gives the interval of time needed by the OC issuer to ramp its power up or down by p_{min}, starting from a synchronized state.

An exercised OC will be called *admissible* if the implemented values for the exercise time t_{ex}, the start time $t_{CPStart}$, and the stop time t_{CPStop} satisfy the following physical feasibility conditions, where the ramp start time t_{RStart} is derived from (24):

Physical Feasibility Conditions:

$$t_{ex} \ \leq \ t_{RStart} \tag{28}$$

$$t_{RStart} \ \leq \ t_{CPStart} \tag{29}$$

$$t_{CPStart} \ < \ t_{CPStop} \tag{30}$$

More precisely, once an OC is exercised at some particular time $t_{ex} \in T_{ex}$, the subsequently implemented controlled power start time $t_{CPStart} \in T_{CPStart}$ must satisfy the physical feasibility conditions (28) and (29). Once such a start time is communicated to the OC issuer, this issuer must complete its synchronization to the grid during the *start-up delay* interval

$$T_{SUD} \quad = \quad [t_{ex}, t_{RStart}] \, , \tag{31}$$

and complete its ramping up or down by p_{min} during the ramping interval (27). The issuer must then be able to follow a power command signal $p^{\star}$ with associated ramp rates r that satisfy the following criteria: (i) the power command signal $p^{\star}$ starts at time $t_{CPStart}$ and concludes at some time $t_{CPStop} \in T_{CPStop}$ that satisfies the physical feasibility condition (30); (ii) the power command signal $p^{\star}$ satisfies $p^{\star}(t) \in P_c$ for each $t \in [t_{CPStart}, t_{CPStop}]$; and (iii) the ramp rate r satisfies $r(t) = \partial p^{\star}(t)/\partial t \in R_C$ for each $t \in [t_{CPStart}, t_{CPStop}]$.

Given any OC (13), and given any admissible $t_{CPStop} \in T_{CPStop}$ for this OC, the *controlled duration* d for the OC can be derived as

$$d \ = \ t_{CPStop} - t_{CPStart} > 0 \tag{32}$$

The interval D_C of admissible controlled durations d for the OC thus takes the form

$$D_C = [d_{min}, d_{max}] \, , \quad \text{where } 0 < d_{min} \leq d_{max} \tag{33}$$

The rights and obligations of the counterparties to the OC (13) can now be succinctly stated: The OC holder has the right, but not the obligation, to secure up/down power from the OC issuer by means of any admissible exercise of the OC's contractual terms.

The total up/down energy delivered by an OC issuer under any admissible exercise of the OC can be measured, ex post, by

$$e_{tot}^{OC} \;=\; \int_{t_{RStart}}^{t_{CPStop}} p(t)dt \tag{34}$$

where $p(t)$ is the actual up/down power increment of the OC issuer at time t. The compensation for (34) is not included in the OC's premium. Rather, all services rendered after the exercise of the OC are instead compensated through the performance payment method ϕ appearing among the OC's contractual terms. For example, the OC holder could be required to compensate the OC issuer ex post for the up/down energy delivery (34) by means of a payment taking the form

$$\text{EnergyPayment} \;=\; \mid \int_{t_{RStart}}^{t_{CPStop}} \phi(t)p(t)dt \mid \quad , \tag{35}$$

where $\phi(t)$ (\$/MWh) is an exercise price for delivery time t that is contractually pre-specified through the performance payment method ϕ in (23).

Two types of swing OCs (13) issued by off-line generators are graphically illustrated in parts (b) and (c) of Fig. 2. Each OC is an up option with swing permitted in both the controlled power increment p and the controlled ramp rates r. However, the interval $P_C = [p_{min}, p_{max}]$ of possible controlled power increments has a positive lower bound $p_{min} > 0$ in case (b) and a zero lower bound $p_{min} = 0$ in case (c). For each option (b) and (c), the contract exercise time t_{ex}, the controlled power start time $t_{CPStart}$, and the controlled power stop time $t_{CPStart}$ are contractually specified as fixed values t_{ex}, $t_{CPStart}$, and $t_{CPStart}$, respectively; hence, by (24) and (32), the derived ramp-start time t_{RStart} and the controlled duration d are also fixed values. The shaded areas in (b) and (c) represent the contractually permitted range of controlled power increments and ramp rates, and the black curves traversing these shaded areas illustrate contractually permitted command signals p^* for the power increments p.

More precisely, the up swing OC depicted in part (b) of Fig. 2 is for an off-line generator that must be synchronized to the grid before it can begin to inject power into the grid. The contract exercise time is t_{ex}. Assuming the contract holder exercises the swing option at t_{ex}, the interval of time needed for this synchronization is indicated by the start-up delay $T_{SUD} = [t_{ex}, t_{RStart}]$. Once synchronized, the generator then needs an additional interval of time, $T_{RI} = [t_{RStart}, t_{CPStart}]$, to ramp up to p_{min} at $t_{CPStart}$. At time $t_{CPStart}$ the generator is then ready to respond to any power command signal $p^\star$ whose magnitude stays between p_{min} and p_{max} and whose ramping rate stays between $-r_{min}$ and r_{max} over the time interval from $t_{CPStart}$ to t_{CPStop}.

The up swing OC depicted in part (c) of Fig. 2 differs from the up swing OC depicted in part (b) in one key regard: namely, the interval P_C of possible controlled power increments now ranges from $p_{min} = 0$ to $p_{max} > 0$. Consequently, under this contract no ramping occurs prior to the controlled power start time $t_{CPStart}$; that is, all ramping is controlled.

A *fixed* OC is graphically illustrated in part (d) of Fig. 2. The contractually specified power increment path is a horizontal line at a constant power increment level p; that is, $P_C = \{p\}$ and $R_C = \{0\}$. Note the similarity between the fixed FC depicted in part (a) and the fixed OC depicted in part (d). As previously noted, the only distinction between a fixed FC and a fixed OC is that the exercise of the fixed OC is at the discretion of the contract holder.

4 Linked Market Design for the Trading of Standardized Contracts

4.1 Market Design Overview

Our proposed market design envisions the ongoing trading of standardized WPM contracts for energy and reserve, supported by a linked sequence of forward markets. The goal of this linked market design is to facilitate the efficient procurement of adequate energy and reserve for each operating hour of each operating day.

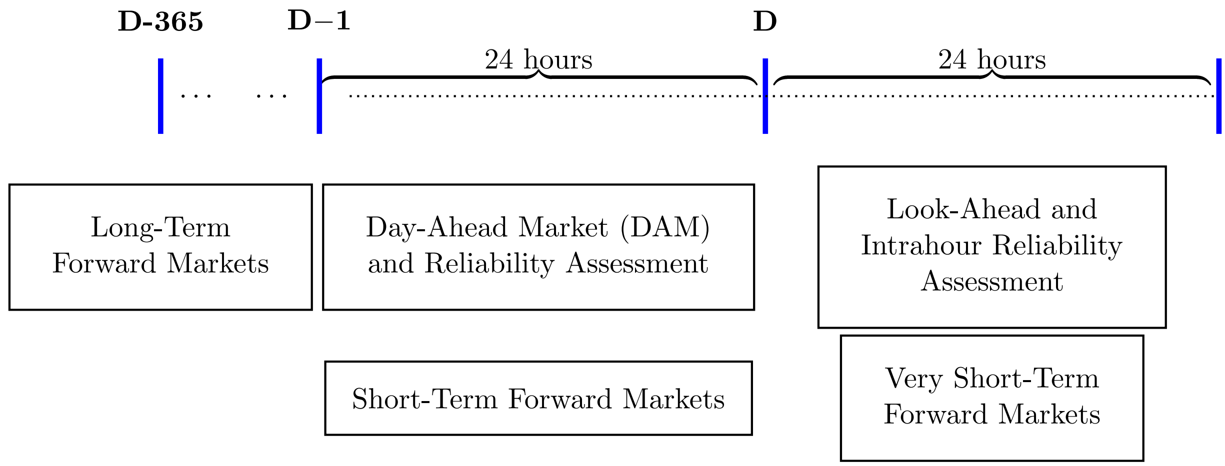

Figure 3: Linked Forward Markets Permitting the Advanced Procurement of Energy and Reserve for an Operating day D.

As indicated in Fig. 3, we recommend the inclusion in this linked sequence of one or more *Long-Term Forward Markets (LTFMs)* with planning horizons of at least a year in order to encourage the appropriate entry of new generation capacity. We also recommend the inclusion of one or more *Short-Term Forward Markets (STFMs)* with planning horizons measured in hours, such as a Day-Ahead Market (DAM), to facilitate advanced planning for real-time operations. Finally, we recommend the inclusion of one or more *Real-Time Markets (RTMs)* with a planning horizon of one hour or less in order to further address energy imbalances in near real-time.

Each of these forward markets is to be organized as an ISO-managed exchange for the trading of WPM contracts subject to system constraints. The ability to specify system constraints with any exactitude will presumably diminish as the length of the planning horizon increases. Nevertheless, system reliability considerations such as anticipated long-term capacity needs might still be important to incorporate even in LTFMs.

The portfolio of pre-existing and newly cleared contracts resulting from the operation of each forward market is to be carried forward on the books of the ISO. This permits a two-way linkage among forward markets. The outcomes of each current forward market can be conditioned not only on all still-active contracts cleared in past forward markets but also on opportunities to procure additional contracts in future forward markets.

The purpose of this linked market design is to provide support for the wholesale trading of energy and reserve products, not to monopolize such trading. GenCos, LSEs, and other types of participants are free to engage in other types of trading. For example, they are free to hedge their price risk through private bilateral contracting or mediated financial markets.

In the following sections we provide brief discussions of the envisioned operations for an illustrative LTFM, STFM, and RTM in our proposed linked forward market sequence. A more detailed discussion of implementation issues is provided in Appendix B.

4.2 Long-Term Forward Market (LTFM)

In "energy-only" markets, resources are compensated for energy and ancillary services but receive no additional payments for capacity [38]. As explained in [11,12], a common shortcoming of energy-only markets in practice has been that they fail to generate sufficient revenue for GenCos to enable coverage of their fixed capital costs.

This "missing money" problem has arisen due to various forms of out-of-market mechanisms and regulations that have been imposed in these markets in order to maintain reliability.[11] It is a serious problem that threatens the replacement of capital and deters new entry and investment.

As depicted in Fig. 3, our proposed sequence of linked forward markets includes one or more LTFMs with a planning horizon of at least a year in order to address this missing money problem. Below we focus on the operation of a single LTFM that takes place well in advance (one or more years) of a specific operating hour H of a specific operating day D.

The LTFM is organized as an ISO-managed exchange for the trading of WPM contracts subject to system constraints. The market participants (MPs) in the LTFM include generation companies (GenCos), demand response resources (DRRs), and load-serving entities (LSEs).[12] These MPs can submit self-scheduled energy outcomes from privately negotiated bilateral trades, supply offers and demand bids for FCs, and supply offers for OCs. The submission of demand bids for OCs (reserve products) is restricted to the ISO, which has a fiduciary responsibility to ensure system reliability as well as system efficiency.[13]

Following the conclusion of the bid/offer submission process, the ISO matches offers to bids in merit order subject to system constraints. The output of the LTFM includes a portfolio $\mathcal{P}(\mathcal{H},\mathcal{D})$ of cleared WPM contracts consisting of both FCs and OCs. An FC obligates the holder to take delivery of up/down energy during hour H, and an OC provides the ISO with the right, but not the obligation, to take delivery of up/down energy during hour H. This portfolio can be further adjusted in subsequent LTFMs, in subsequent STFMs such as a DAM conducted on day D−1, in subsequent RTMs such as might be held during reliability assessment periods immediately prior to the start of hour H, and in real-time operations during hour H.

[11] Administratively-capped spot energy prices sometimes prevent energy prices from reflecting relative scarcity of capacity. This limits generator revenues and is one source of the "missing money" in energy-only markets. Generator supply-offer caps, reliability-must-run (RMR) designations for generators, and/or out-of-market (OOM) dispatch are additional administrative mechanisms that can cause "missing money" problems.

[12] Although we do not preclude financial traders with no physical generation or customer service obligations from participating in the ISO-managed forward markets, this report focuses on physically-covered MPs who can contribute to the satisfaction of physical grid constraints.

[13] An alternative possibility would be to allow LSEs to submit OC demand bids as well as the ISO. However, this raises a critical question: Would private profit-seeking LSEs have the appropriate incentives and/or system information to properly exercise OCs for the assurance of *system* reliability?

4.3 Short-Term Forward Market (STFM)

No matter how carefully agents plan to meet future energy and reserve needs through LTFM transactions, unexpected events will arise that necessitate adjustments in these plans as operating points draw near. For the ISO, updated system data could affect its anticipated reserve needs. For GenCos, changes in fuel costs and needed maintenance repairs could affect their generation supply offers. For LSEs, improved weather data could affect their forecasts for the energy usages of their customers and hence their demand bids.

The need for an STFM is currently recognized in all seven U.S. ISO-managed energy regions through incorporation of a DAM. The DAM permits MPs to prepare in advance for intended next-day real-time market operations. It consists of two integrated or tightly coupled optimizations: *Security Constrained Unit Commitment (SCUC)*, which determines the particular set of resources committed for possible next-day Dispatch;[14] and *Security Constrained Economic Dispatch (SCED)*, which determines location-specific cleared supplies and demands for reserve and/or energy for next-day operations, together with location-specific prices for these cleared amounts, conditional on the SCUC unit commitments.[15]

The market design proposed in this report recommends the inclusion of at least one STFM, such as a DAM. However, it recognizes that energy and reserve products traded in an STFM can usefully be represented in standardized form, as newly created WPM contracts, and that any STFM should be only one among a sequence of linked forward markets aimed at ensuring the efficient procurement of adequate energy and reserve for real-time operations.

Specifically, we envision the ISO as a clearinghouse that enters into an STFM in advance of an operating day D with an existing portfolio of WPM contracts already recorded on its books. The ISO wheels this existing portfolio through the STFM, permitting it to be adjusted through a bid/offer-based SCUC/SCED optimization.

More precisely, as for the LTFM, the MPs of the STFM consist of GenCos, DRRs, and LSEs. These MPs can submit self-scheduled quantity outcomes from privately negotiated bilateral trades, supply offers and demand bids for FCs, and supply offers for OCs. The submission of demand bids for OCs is restricted to the ISO.

Following the conclusion of this bid/offer process, the ISO undertakes a SCUC/SCED optimization to determine unit commitments, GenCo dispatch levels, cleared LSE demand bids, and settlement payments conditional on the bids/offers of the MPs, the OC bids of the ISO, system constraints, and linkages to prior and subsequent contract procurement processes. The linkages permit the ISO to plan to secure up/down energy for next-day balancing needs from four different sources: namely, (i) the use of previously cleared FCs; (ii) the exercise of previously cleared OCs; (iii) the clearing of new FCs/OCs in the STFM; and (iv) the planned clearing of new FCs/OCs in subsequent STFM/RTM processes.

[14] For example, the outputs of MISO's SCUC optimization for any next-day operating hour include for each resource a "commitment flag" indicating its eligibility (1) or not (0) for supply of energy and a "regulation flag" indicating its eligibility (1) or not (0) for supply of "regulation reserve," i.e., reserve that can respond immediately to automatically generated central control signals [47].

[15] For example, as detailed in [46], some regions such as ISO-NE have day-ahead energy markets based on MP bids/offers for energy, with reserve procured separately through supporting markets and processes. Other regions such as MISO have co-optimized energy/reserve DAMs in which MPs submit demand bids for energy and supply offers for both energy and reserve but only the ISO submits demand bids for reserve.

One particular way in which an ISO could wheel a portfolio of contracts through an STFM is concretely illustrated in [44] for the specific case of a DAM. The DAM power balance equations are augmented with ISO-determined “virtual” supply offers representing pre-existing and/or anticipated procurement of energy and reserve obtained through non-DAM transactions. These offers permit the ISO on any day D−1 to plan to achieve power balance on day D by means of a cost-efficient mix of contracts entered into at different times prior to each operating hour of day D; the ISO is no longer forced to act in the DAM as though physical power balance on day D can only be achieved by means of contracts newly procured through the DAM on day D−1. In addition, the DAM power balance equations are augmented with ISO-determined “virtual” demand bids. These bids permit the ISO to adjust the next-day net fixed load forecasts implied by MP bids/offers for non-dispatchable loads and for non-dispatchable generation (treated as negative load) in cases in which inaccuracies in these MP forecasts are detrimental to system reliability or system efficiency.

The linked DAM formulation [44] is illustrated for both day-ahead energy markets and co-optimized day-ahead energy/reserve markets. Moreover, with its emphasis on the use of physically-covered call options as reserve instruments, it is also shown to provide natural support for a stochastic linked DAM in which ISO uncertainties are handled by means of contingency planning implemented via probability-weighted scenarios.

4.4 Real-Time Market (RTM)

As stressed throughout earlier sections, an implementable market design for power systems must take into account the physical constraints on energy delivery. A key constraint is that actual energy loads (plus losses) for a power grid must be balanced by energy generation at each point in time.

The RTMs currently implemented in each of the seven U.S. ISO-managed energy regions are very short-term forward markets in which the ISO attempts to ensure needed physical balance between five and ten minutes in advance of an operating hour H.[16] A special characteristic that distinguishes these RTMs from forward markets with longer planning horizons is that only the ISO is permitted to make demand bids for energy in these markets.

In particular, at the time of an RTM, the ISO's forecast for load during hour H is treated as actual fixed (non-price-sensitive) load that must be met unless curtailed in some way (e.g., through DR exercise or direct load shedding). This use of the ISO's load forecast in an RTM is equivalent to permitting the ISO to submit a demand bid for a simple “block energy” type of fixed FC.

Our linked market design envisions the retention of an ISO-managed RTM to ensure physical balancing needs. Energy and reserve products in this RTM are to be represented using standardized FC and OC contracts, respectively.

The ISO managing the RTM functions as a clearinghouse with some specialized rights. It enters the RTM holding a pre-existing portfolio of contracts, which is then adjusted via RTM trading. The MPs are permitted to submit supply offers for both FCs and OCs; but only the ISO is permitted to submit demand bids for FCs and OCs. The start and stop times for the FCs and OCs offered

[16] Existing RTMs are cleared every five to ten minutes. There are no shorter-term markets at present. However, very-short-term non-market processes are used to help maintain grid balance, such as administratively-determined AGC.

into the RTM must be consistent with the RTM run time. For instance, if the RTM runs every five minutes, starting at the top or each hour, examples of valid contract start and stop times would be 9:05am, 12:10pm and 2:00pm.

Note, in particular, that this RTM formulation allows the ISO to submit RTM demand bids for swing FCs. That is, it permits the ISO to procure swing for known swing needs. For example, it permits the ISO to plan for the coverage of fluctuations in hour H load whose upper and lower bounds are known with near-certainty by the time of the RTM. The costs for this swing FC procurement, as with all other costs incurred by the ISO in the course of its market management functions, must be allocated to the MPs in order for the ISO to retain its required nonprofit status.

In summary, the ISO managing the RTM can plan to procure up/down energy to cover anticipated real-time energy needs by the following three means: (i) the use of pre-existing FCs; (ii) the exercise of pre-existing OCs; and/or (iii) the use of FCs newly cleared in the RTM. In addition, the ISO can replenish reserve to maintain acceptable reliability thresholds by submitting demand bids for OCs.

5 Contract Deployment in Real-Time Operations

During real-time operations, the goal of the ISO is to be able to rely on a particular combination of FCs and OCs from the existing portfolio of WPM contracts to obtain sufficient energy to balance actual load at least cost while maintaining an appropriate level of reserve. The needed up/down energy is to be obtained either through firm up/down energy deliveries resulting from existing FCs or through up/down energy deliveries resulting from the exercise of existing OCs.

A *fixed* FC or OC can serve as block energy, such as when a contingency occurs and replacement energy is needed. Under the terms of a fixed FC (1), the issuer is obligated to deliver a fixed up/down power increment p at a designated location k for a designated duration $[t_{PStart}, t_{PStop}]$. If the issuer's power increment is not at the contractually specified level p prior to the contractually specified start-time t_{PStart}, then the issuer is obligated to ramp up (or down) at rate r_{SU} to achieve p by time t_{PStart}.

A *swing* FC or OC can provide not only block energy but also power increments suitable for more finely tuned load-balancing and regulation, depending on which of its contractual terms have swing. For instance, an FC with swing only in its power output could be used as replacement energy, where its power increment p is set to a value within the contractually specified interval P_C of allowable controlled power increments. In contrast, an FC with swing in several of its contractual terms, such as its controlled power increments and its controlled ramp rates, can be used for load-following and regulation.

6 Looking Forward

In the future, the co-optimization of energy and reserve will be complicated by several factors. First, the level of uncertainty in both generation and load is increasing rapidly. Second, and related, the provision of reserve will increasingly involve participation from both the supply and demand sides of the market. Not only will demand side participation increase, but some resources, such as energy storage systems, will also blur the boundaries between the supply and demand sides.

The uncertainty in generation is increasing as a function of renewable energy penetration. In the absence of bulk energy storage systems, or some alternative means of providing back-up (e.g., suitably coordinated demand response resources), wind and solar power plants are difficult to dispatch due to large forecast errors. Large-scale power systems, which were designed around directly-coupled synchronous generators, must be operated differently to accommodate the prevalence of variable generation. The uncertainty in load is increasing due to the emergence of demand response resources. Demand-side participation is expected to evolve to take a variety of forms, including industrial loads with non-critical processes, large megawatt-scale aggregators, and distributed "smart" appliances. Another factor with the potential to increase load uncertainty is the anticipated adoption of plug-in electric vehicles.

Taken together, the growing uncertainty in generation and load will drive an increase in the amount of regulating reserve required to maintain a balance of power in the system. A separate problem is that of specifying the amount of contingency reserve required to maintain system security and stability. Often, rules of thumb and engineering judgment are used to specify the required amount of contingency reserve. As the dynamics of large-scale power systems change, and transmission systems are pushed ever closer to their capacity limits, these rules of thumb may no longer be sufficient. Hence, the specification of contingency reserve requirements must be driven by a computational analysis of credible contingencies.

As the participants and their roles within electricity markets change, the methods used to co-optimize energy and reserve must evolve to keep pace. In this report we propose a new formulation of U.S. ISO-managed wholesale electric power markets for improved reliability and efficiency of energy/reserve procurement.

This new market formulation represents energy and reserve products in terms of standardized contracts whose terms cover a broad range of system service needs, including power increment, ramp rate, and energy capacity. These contracts provide financial instruments for the pricing and procurement of energy and reserve in forward markets as well as blueprints for the physical deployment of energy and reserve in real time. To ensure a level playing field, all resources capable of satisfying system service needs can submit supply offers for the provision of these needs, regardless of their physical forms.

Another new facet of this new market formulation is the navigation of a sequence of forward markets, each connected to the other through an ISO-managed portfolio of contracts. As the planning horizon in the sequence of forward markets decreases, forecasts of generation and load improve, thereby reducing planning uncertainty. Conversely, the potential for price volatility increases as the spot market approaches. Long-term forward markets with a planning horizon of a year or more are envisioned to encourage the entry of new generation capacity. Short-term forward markets with a planning horizon measured in hours are envisioned to facilitate improved planning for real-time operations.

A key question is whether this new market formulation would result in more efficient market operations. We conjecture that procuring reserve in this new market would be more efficient over the short term, as the ISO could choose those resources that best match its needs rather than being forced to conform to rigidly specified reserve product categories. Procuring reserve should be more efficient over the long term as well, since compensation based on actual contribution should provide better incentives for new reserve capacity to enter the market. Moreover, having organized long-term markets with standardized contracts should reduce transaction costs and facilitate price discovery for both energy and reserve.

In the next phase of this project we plan to examine whether this new market formulation might actually lead to greater efficiency in short term operations. We will develop a simulation of linked short-term and real-time markets, and run this simulation for a small test system. To do this, we plan to construct new SCUC and SCED optimization methods consistent with the market structure defined in this report. Optimization rules will also be separately implemented for an existing wholesale market formulation. This will enable us to compare the cost of operating the same resources against the same load profile using the two different market formulations.

In order to implement the market optimizations for the new formulation, a number of practical issues need to be resolved. One issue is the representation of reserve requirements. Appendix C outlines two possible ways this representation could be done: namely, in the time domain, or in the frequency domain. In order to optimize reserve, an approach must be selected and made operational. Another concern is how market clearing prices for the proposed contracts are to be found, given that the terms of these contracts (in areas such as start time, ramp rate, and output flexibility) can be very diverse.

Beyond this current project, a future step could be to incorporate additional forward markets into the initial test case, such that the linked forward markets would include a planning horizon of multiple years ahead of actual operations. The long-term operating costs of the new market would be compared against the long-term operating costs of an existing market. In this way, the long-term efficiency of the new market formulation could be explored.

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Appendix A Numerical Examples for Energy/Reserve Products in Standardized Contract Form

A.1 Overview

This appendix illustrates how the FC and OC formulations (1) and (13) can be used to represent standard types of energy and reserve products traded in current U.S. ISO-managed wholesale electric power markets.[17] The indicated contract value for FCs, as well as the indicated premiums and performance payments for OCs, are provided only to suggest possible forms these payments could take; no claim is made that these are the most appropriate forms for these payments.

A.2 Fixed FC offered into an STFM by a GenCo

1. Suppose a fast-start generation company (GenCo) located at bus k offers into an ISO-managed DAM on day D$-$1 a fixed FC that has the following contractual terms:

$$\begin{aligned}
\text{fixed FC} &= \text{Contract type} &(36)\\
k &= \text{Location} &(37)\\
\text{direction} &= \text{Up} &(38)\\
r_{SU} &= 12 \text{ MW/minute} &(39)\\
t_{PStart} &= \text{10:00am on day D} &(40)\\
p &= \text{12MW} &(41)\\
t_{PStop} &= \text{11:00am on day D} &(42)
\end{aligned}$$

   Suppose this FC is cleared by the ISO at 2:00pm on day D$-$1 as part of the ISO-determined DAM commitment, dispatch, and pricing solution for day D. This cleared FC requires the GenCo to provide power on day D in accordance with the following contractually specified terms. At t_{PStart} = 10:00am on day D the GenCo must deliver an (up) power increment p = 12MW at bus k, and the GenCo must maintain this power increment until t_{PStop} = 11:00am on day D.

   Assuming the locational Marginal Price (LMP) at bus k for hour 10-11:00am of day D is LMP_k = \$35/MWh, the procurement payment that the ISO pays to the GenCo on day D$-$1 for this cleared FC is \$35/MWh $\times$ 12MW $\times$ 1h = \$420. Here LMP_k = \$35/MWh is the DAM Locational Marginal Price (LMP) at bus k for hour 10-11:00am of day D as determined by the DAM solution on day D$-$1.

2. The preceding DAM example can be generalized to a longer-term forward market by replacing "D$-$1" with "D-n" for arbitrarily large n.

[17] See [46] for a survey of these products.

A.3 Fixed FC offered into an STFM by an energy storage plant

1. Suppose an energy storage plant located at bus k submits an offer for a fixed FC into an ISO-managed DAM on day D−1, where this FC has the following contractual terms:

$$\text{fixed FC} = \text{Contract type} \quad (43)$$
$$k = \text{Location} \quad (44)$$
$$\text{direction} = \text{Up} \quad (45)$$
$$r_{SU} = 5 \text{ MW/minute} \quad (46)$$
$$t_{PStart} = \text{8:00am on day D} \quad (47)$$
$$p = \text{15MW} \quad (48)$$
$$t_{PStop} = \text{9:00am on day D} \quad (49)$$

   Suppose this fixed FC is cleared by the ISO at 2:00pm on day D−1 as part of the general DAM commitment, dispatch, and pricing solution for day D. This cleared FC requires the energy storage plant to inject up-power at bus k on day D in accordance with the following contractually specified terms. The energy storage plant provides an up-power increment $p = 15$MW starting at time $t_{PStart} =$ 8:00am on day D and maintains this up-power increment until time $t_{PStop} =$ 9:00am on day D. The energy storage plant will begin injecting power at $t_{RStart} =$ 7:57am on day D, ramping up at a rate of $r_{SU} =$ 5MW/minute until it reaches $p =$ 15MW at t_{PStart}.

   Suppose the DAM LMP at bus k for hour 8-9:00am on day D is \$30/MWh, where this LMP is determined as part of the DAM solution on day D−1. Then the total procurement payment made by the ISO to the energy storage plant on day D−1 for this cleared down FC is \$30/MWh times the 15MWh of up-energy delivered during 8-9:00am, for a total of \$450.

2. The preceding DAM example can be generalized to a longer-term forward market by replacing ”D−1” with “D-n” for arbitrarily large n.

A.4 Fixed OC offered into an LTFM by a GenCo

Suppose a fast-start GenCo is currently considering the construction at bus k of a new fast-ramping power plant that has a rated capacity of 125MW. The GenCo would like to offer 20% (25MW) of this rated capacity into a long-term forward market as fixed OCs that could be employed as contingency reserve during each day of 2014, the first year of the plant's operations. Specifically, this portfolio consists of a collection of fixed OCs OC^D, where D $= 1, \ldots, 365$ covers all 365 days of 2014. For each D, the contractual terms characterizing OC^D are as follows.

$$
\begin{aligned}
\text{fixed OC} &= \text{Contract type} && (50)\\
k &= \text{Location} && (51)\\
\text{direction} &= \text{Up} && (52)\\
r_{SU} &= \text{25MW/minute} && (53)\\
T_{ex} &= \{t_{ex}\},\ \text{where } t_{ex} = \text{11:50pm on day D}-1 && (54)\\
T_{CPStart} &= \{t_{CPStart}\},\ \text{where } t_{CPStart} = \text{12 midnight on day D}-1 && (55)\\
P_C &= \{p\},\ \text{where } p\ = 25\,\text{MW} && (56)\\
R_C &= \{r\},\ \text{where } r\ = 0\,\text{MW/minute} && (57)\\
T_{CPStop} &= \{t_{CPStop}\},\ \text{where } t_{CPStop} = \text{12 midnight on day D} && (58)\\
e_{cap} &= \text{Not applicable} && (59)\\
\phi\text{-method} &= \text{\$20/MWh} && (60)
\end{aligned}
$$

The GenCo could use the premium it receives from the sale of these OCs (and other similar portfolios) in order to secure long-term financing for the plant. Additionally, if any of the options are exercised, the GenCo receives additional compensation for delivered up/down energy at the price \$20/MWh determined by the ϕ-method (60).

A.5 Swing OC for regulation reserve offered into an STFM by an energy storage plant

1. Suppose an on-line energy storage plant at location k an ISO-managed DAM on day D$-$1 a swing OC having the following form:

$$
\begin{aligned}
\text{swing OC} &= \text{Contract type} && (61)\\
k &= \text{Location} && (62)\\
\text{direction} &= \text{Up} && (63)\\
r_{SU} &= \text{1.5MW/minute} && (64)\\
T_{ex} &= \text{Between 2:00pm on day D}-1 \text{ and 9:58am on day D} && (65)\\
T_{CPStart} &= \text{Between 9:00am and 9:59am on day D} && (66)\\
P_C &= \{p\},\ \text{where } p = \text{3MW} && (67)\\
R_C &= \{r\},\ \text{where } r\ = \text{0MW/minute} && (68)\\
T_{CPStop} &= \text{Between 9:01am and 10:00am on day D} && (69)\\
e_{cap} &= \text{3MWh} && (70)\\
\phi\text{-method} &= \text{Pay for called energy using RTM LMPs for day D.} && (71)
\end{aligned}
$$

   Suppose this swing OC is cleared at 2:00pm on day D$-$1. This cleared swing OC gives the ISO p=3MW of up-regulation that can be flexibly deployed starting at any controlled power start time $t_{CPStart}$ between 9:00am and 9:59am on day D and ending at any controlled power start time t_{CPStop} between 9:01am and 10:00am on day D, subject to the physical feasibility conditions (28) through (30).

   The ISO can exercise the OC anytime between 2:00pm on day D$-$1 and 9:58am on day D. However, the ISO must take into account that the energy storage plant has a start-up ramp rate of r_{SU} = 1.5MW/minute, hence it will need 2 minutes to ramp up to the required power increment of 3MW. If, for example, the ISO finds that it needs 3MW of up-regulation during 9:40am-9:50am on day D, implying that $t_{CPStart}$ = 9:40am, it will need to exercise the OC no later than t_{RStart} = 9:38am on day D to be able to use the energy storage plant to supply the needed up regulation of 3MW starting at 9:40am. This follows because

$$\text{1.5MW/minute} \times \text{[9:40am - 9:38am]} = \text{3MW} \tag{72}$$

If the OC is exercised at t = 9:38am on day D for a controlled power start time $t_{CPStart}$=9:40am on day D, and the energy storage plant maintains a 3MW power injection until t_{CPStop} = 10:00am on day D (a duration of twenty minutes), the resulting actual 3MW × (1/3)h = 1MWh of up-energy supplied by the energy storage plant will be compensated in accordance with the performance payment method ϕ. In particular, if LMP_k^{RTM} = \$30/MWh is the real-time market LMP determined at bus k during the hour between 9:00-10:00am on day D, the energy storage plant will receive \$30 in compensation.

2. Suppose an on-line energy storage plant at location k offers into a DAM on day D−1 an OC having the same form as above *except* that the OC is for down-regulation rather than for up-regulation. The energy storage plant can supply down-regulation either through a decrease in its current power output or through an increase in its charging rate (load).

   If the OC is cleared at 2:00pm on day D−1, this gives the ISO 3MW of down-regulation that can be flexibly deployed starting at a controlled power start time $t_{CPStart}$ between 9:00am and 9:59am on day D and concluding at a controlled power stop time t_{CPStop} between 9:01am and 10:00am on day D, subject to the physical feasibility conditions (28) through (30). The only difference is the direction of the ramping (down) that will be needed once the OC is exercised at least two minutes prior to any particular desired start time $t_{CPStart}$.

Appendix B Practical Implementation Issues for the Linked Market Design

B.1 Determination of FC/OC Procurement Payments

The outcomes of each forward market optimization include cleared supplies for FCs (energy products) and OCs (reserve products) for some particular hour H of some particular operating day D. These outcomes can be represented as a portfolio of WPM contracts carried on the books of the ISO and settled through the ISO, acting as a central clearinghouse.

In addition, the outcomes of these optimizations include procurement payments for these cleared contracts (referred to as "premiums" for option contracts such as OCs). The determination of these procurement payments appears to be relatively straightforward for "block-energy" FCs and OCs, that is, for FCs and OCs without swing in their contractual terms and without significant start-up delays and ramping intervals.

For example, the procurement payment for a cleared block-energy FC with delivery location k can be determined by calculating the shadow price λ_k (\$/MWh) for the power balance equation at location k and then using this price to place a value on the FC's obligatory energy delivery at k. The premium of a cleared block-energy OC for the potential delivery of up/down energy $e^*_{r,k}$ (MWh) at a location k, where the requirement at k for this particular type of reserve is $\bar{e}_{r,k}$, can be determined by calculating the shadow price μ_k (\$/MWh) for the reserve requirement inequality constraint $e_{r,k} \geq \bar{e}_{r,k}$ and then using this price to place a value on $e^*_{r,k}$.

However, determining the procurement payments for other types of FCs and OCs will require that careful consideration be given to the multiple services they provide. For example, in addition to the overall delivery of up/down energy, an FC or OC could contribute fast start-up, fast ramping, and/or desirable swing (flexibility) in its possible exercise times, start times, controlled power increments, controlled ramping rates, and/or stop times. This issue will be examined with care in future studies.

B.2 Determination of OC Performance Payments

Recall from Section 3.4.2 that the performance payment method ϕ for an OC appears among its contractual terms. Hence, ϕ is an input to the market process, not an outcome.

As discussed in Oren [39, Sect. II.C.1], one possible way to determine the performance payment method would be to have the ISO pre-set a single common exercise price for all OCs, which then functions as a regulatory policy parameter. OC premia can be expensive; hence, one objective in setting the exercise price as a policy parameter could be to keep premia relatively low so that the up-front reserve cost for the ISO and ultimately for the LSEs is kept relatively low. In particular, the exercise price could be set so that OCs are "out-of-the-money" most of the time, which would tend to lower their premia. For example, the exercise price might be set to be 50% or more of an administratively-determined energy price cap.

Another possibility would be to allow forward market participants to offer OCs that have various pre-set exercise prices and then let the market decide which exercise prices are viable. Still another possibility would be to have the performance method specify the calculation method to be used for the determination of an exercise price conditional upon contract exercise, with no pre-specification of its exact value. For example, as illustrated in Appendix A, example A.5, an OC could stipulate that the exercise price to be paid conditional upon exercise of the contract is the price for energy to be determined in some market process occurring after this exercise.

One important consideration restricting the determination of the performance payment method ϕ in practice, however, is that it must provide payment for performance sufficient to attract adequate supplies of each type of reserve. That is, it must attract supplies of OCs sufficient to cover the reserve requirements set by the ISO to ensure the fulfillment of NERC regulations.

B.3 Allocation of Reserve Costs

Under our proposed market design, the ISO functions as a clearhouse for WPM contract trading in each forward market in a linked sequence. All MPs in these markets with cleared demand bids make procurement payments for this cleared demand to the ISO, and all MPs in these markets with cleared supply offers receive their procurement payments for this cleared supply from the ISO. The nonprofit ISO is required to distribute any resulting net payments ("congestion rent") back to the MPs in some form to avoid taking a financial position in these markets.

However, in conformity with current practices, the ISO also has some special rights in each of these forward markets. Specifically, only the ISO is able to submit demand bids for OCs (reserve); hence, only the ISO holds and exercises OCs.

To avoid having the ISO take a financial position in these forward markets, we therefore propose (in conformity with current practice) that all costs incurred by the ISO from OC procurement and exercise be allocated to the LSEs in proportion to their realized loads, where this allocation is adjusted for any reserve the LSE self-supplies as a Demand Response Resource (DRR).

For example, suppose an LSE's customers account for $x_k\%$ of the load at location k during hour H of day D, and suppose the regulation reserve obligation at location k is $\bar{r}_k$. Suppose, also, that the total premium and exercise-price payment costs for the provision of $\bar{r}_k$ during hour H of day D turns out to be $C(\bar{r}_k)$. Then the LSE's gross regulation reserve obligation at location k during hour H of day D is $x_k C(\bar{r}_k)$. However, this gross reserve obligation is then adjusted downward by the amount of any cleared regulation reserve that the LSE self-supplies, functioning as a DRR. In similar fashion, reserve obligations could be calculated for the LSE for each different type of reserve product for each different location.[18]

Consequently, under this proposed allocation method, an LSE can meet its reserve obligations using any combination of the following two methods:

1. Direct cash payments to the ISO for allocated net costs of reserve procurement;
2. Self-supply of reserve in a forward market through cleared OC supply offers submitted by the LSE functioning as a DRR.

In particular, should an LSE so choose, it can meet its reserve obligations entirely through cash payments to the ISO.

The rationale for allocating reserve costs to the LSEs is that the function of reserve is to ensure system reliability for the benefit of the LSEs' energy customers. The reserve costs allocated to the LSEs can be passed along to their energy customers through appropriate adjustments in retail

[18] In practice, the formulas for determining LSE forward reserve obligations are complicated by additional considerations, such as load duration and timing.

energy prices, either through increases in regulated rates or through negotiated adjustments in retail energy contract terms.

Another way to proceed, however, would be to consider more carefully the degree to which each MP contributes to the need for reserve, and to allocate reserve costs accordingly. In particular, the need for reserve is related more to ex ante uncertainty about loads and generation levels than to ex post actual loads, the current basis for ISO reserve cost allocation. Thus, it seems reasonable that LSEs who persistently underestimate or overestimate their actual loads through their FC demand bids in forward markets should receive a correspondingly higher allocation of reserve obligations. Similarly, it seems reasonable that GenCos and transmission companies with higher than average unforced outages due to lack of due diligence in equipment maintenance should be charged a portion of the system's reserve costs.

B.4 Contract Performance Periods (Maturities)

Generation capacity investment periods and payback periods tend to be long. Consequently, the financial interest of GenCos is better served by having longer maturities for WPM contracts.

On the other hand, the financial interest of LSEs is better served by having shorter WPM contract maturities because of the possible fluidity of retail customer retention. Providing end-use customers with the ability to "vote with their feet" among alternative retail suppliers is desirable to encourage efficient retailer operations, and several energy regions now permit retail customers to have this flexibility.

There are several approaches to resolving this conflict. First, the settlement of an LSE's reserve obligations could be structured to smooth out the LSE's payments, perhaps taking the form of a monthly payment stream where the payment is guaranteed to remain fixed for some period of time. Second, the ISO could periodically adjust the LSE's reserve obligations based on updated estimates for the LSE's future loads. Third, the ISO could encourage (or permit) the development of secondary contract markets. Having secondary contract markets would allow LSEs and other existing MPs to adjust their contract positions to match their continually changing conditions and would encourage the entry of new MPs who could assume the positions of existing MPs.

B.5 Penalties for Non-Performance

As for current markets for energy and reserve, WPM contract trades in a forward market should be backstopped by penalties for nonperformance. This backstopping could be stipulated in the general rules and regulations constraining market business practices. Backstopping for nonperformance is particularly important for LSEs who are required to satisfy reserve obligations and who may attempt to do so by participating as DRRs in the forward market, submitting supply offers for OCs taking the form of load curtailments or adjustments.

Appendix C Real-Time Representations for Reserve Requirements

Current practices for calculating reserve requirements lack detail and tend to impose arbitrary performance constraints on resources willing to provide them. Reserve requirements must be better defined in order to take advantage of the flexibility given by WPM contracts.

This section introduces two approaches, currently under study, for the representation of reserve requirements. These two approaches are based on time-domain and frequency-domain techniques, respectively.

C.1 Time Domain Representation

An example of typical load profile for a day in a Balancing Authority (BA) and its corresponding Area Control Error (ACE) are shown in Fig. 4. Power system requirements for reserves can be described using balancing duration curves. These balancing duration curves in the up and down directions can be estimated based on historical data and forecasting conditions.

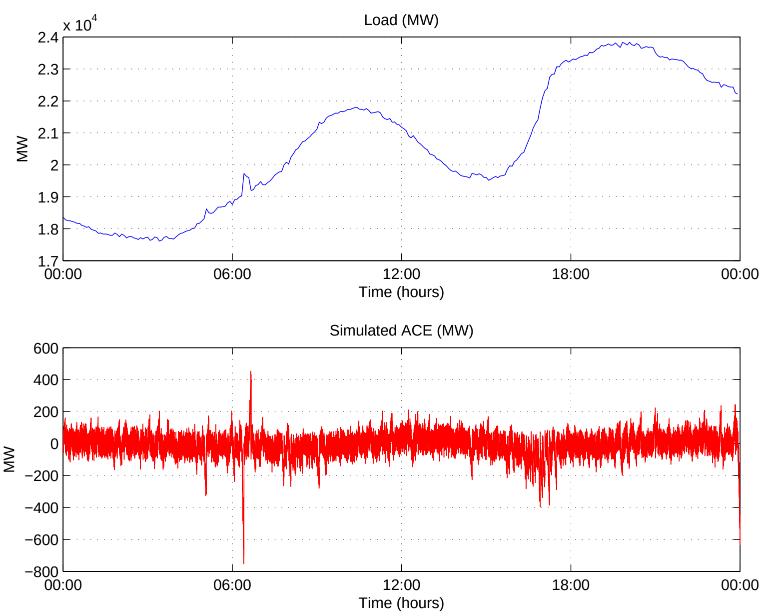


Figure 4: Example of Load (top) and Corresponding ACE (bottom) Signals for a 24-hour Period.

Figure 5 shows an example of the energy balancing duration curve in the up and down direction corresponding to hour 7 of the load profile shown in Fig. 4. This balancing energy duration curve presents the maximum power deviations and their duration. With this information, energy resources can be scheduled based not only on their power capabilities but also their ramp rates and energy availability.

WP contracts provide information on power limits, operational ramp rates, energy capacity, adjustment direction and price. These characteristics can be employed to depict these contracts by means of polygons in the ΔMW - time plane. The portfolio selection problem is then to determine the particular contracts that provide the estimated balancing energy. Graphically, the problem is to use the combination of contracts that cover the area under the balancing duration curve.

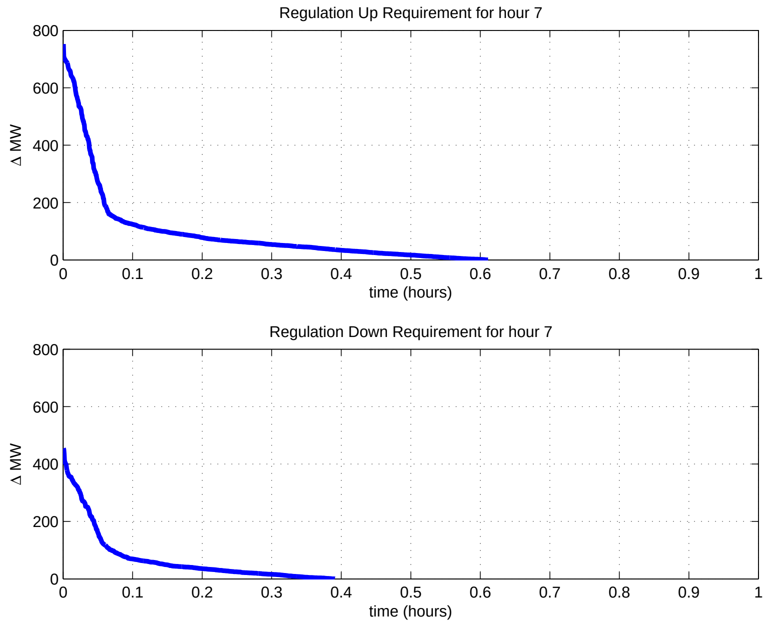


Figure 5: Example of Balancing Energy Duration Curve in the Up (top) and Down (bottom) Directions.

C.2 Frequency Domain Representation

This section explains how the WPM contract forms proposed in this report allow an ISO to convert from contract parameters to frequency domain performance. We outline a frequency-domain approach for determining the required regulating reserves and then performing an economic dispatch that minimizes system costs. The proposed approach involves identifying the frequency domain characteristics of the balancing area, including the interaction with adjacent balancing areas.

In order to guarantee system reliability, an ISO must maintain system frequency at a nominal $60Hz$ (in North America). If generation increases with no change in load, the system frequency will increase. Likewise, if generation decreases with no change in load, the system frequency will fall. The relationship between change in frequency as a function of the change in generation and load is given by [48]

$$\Delta f = \frac{\Delta P_m - \Delta P_L}{Ms + D} \text{ (p.u.)} \tag{73}$$

where M is the aggregate system inertia ($M = 2H$), D is the aggregate load damping constant, ΔP_m is the change in mechanical power of the generators, and ΔP_L is the non-frequency sensitive load change. The system frequency is related to the system generator speed by

$$f = 60\omega \tag{74}$$

where ω is the system speed per unit.

The metric for quantifying the system imbalance is the ACE, defined by NERC (North American Electric Reliability Corporation) as "the instantaneous difference between Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error" [49].

$$ACE = (NI_A - NI_S) - 10\beta(F_A - F_S) - I_{me} \tag{75}$$

The terms in the ACE equation are defined in Table 1 [50].

ACE	Area Control Error (MW)
NI_A	Net actual interchange (MW). A positive number indicates delivering excess generation out of the area.
NI_S	Scheduled net interchange (MW). A positive number indicates scheduling excess generation out of the area.
F_A	The actual system frequency (Hz).
F_S	The scheduled system frequency (Hz), normally 60 Hz.
I_{me}	An adjustment term often manually entered to adjust for known equipment errors (MW).
β	The control area's frequency bias setting (MW/0.1 Hz). This is a negative number.

Table 1: Area Control Error (ACE) terms.

Each balancing authority must review its frequency bias once a year, and the method for calculating the frequency bias is governed by a NERC standard [51]. In most balancing authorities, an Automatic Generation Control (AGC) signal is sent to a subset of the generators to regulate frequency and to maintain the the scheduled power flows between areas. The required frequency control performance is defined by a NERC standard [50], which includes compliance criteria. The minimum required quantity of operating reserves is a function of the region. For the Western Electricity Coordinating Council (WECC), the following minimum operating reserves are required [52]:

- Regulating reserve: sufficient spinning reserve, immediately responsive to AGC to provide sufficient regulating margin to allow the BA to meet NERC's control performance criteria (see BAL-001-0).
- Contingency reserve: an amount of spinning reserve and non-spinning reserve (at least half of which must be spinning reserve), sufficient to meet the NERC Disturbance Control Standard BAL-002-0, equal to the greater of:

  (a) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or

  (b) the sum of five percent of the load responsibility served by hydro generation and 7 percent of the load responsibility served by thermal generation.

In other regions, the amount of regulating reserve is defined as a percentage of the overall load, e.g. 1% of the peak load for the PJM RTO for the on-peak regulation requirement [53]. While the current requirements for operating reserves have met the reliability needs of the system, they often result in rules that discriminate against limited energy devices. Limited energy devices, like electricity storage, often have very high ramp rates, but limited duration. These high ramp rates offer the potential to reduce the amount of required regulating reserves, which would result in a significant cost savings while still maintaining system reliability. Although the current regulating reserve requirements are based on the power system statistics and potential contingencies, they also are heavily influenced by past practices, which may be conservative.

A simplified area model is shown in Figure 6. $P_2(s)$ represents the aggregate model of all generators with frequency droop control, but not connected to the ACG signal. $P_2(s)$ represents the aggregate model of all generators (turbine plus governor) with frequency droop control and connected to the ACG signal. ΔP_{tie} represents the aggregated tie flows to adjacent areas. This is a measurable stochastic input. Variations in load are represented by ΔP_{load}, which is a nonmeasurable stochastic input. Some sort of estimator is required for this parameter.

Determining the required system response to meet the NERC requirements can be formulated as a disturbance rejection problem. Given the expected characteristics of ΔP_{tie} and ΔP_{load}, the shape of $P_1(s)$ and $P_2(s)$ can be calculated so that the NERC requirements are met. Since the system configuration and characteristics change over time, these calculations likely must be performed for a number of different scenarios. The resulting estimates for $P_1(s)$ and $P_2(s)$ quantify the frequency domain aggregate requirements for the governor responsive generators in the system. The AGC-connected generation requirements are described by $P_1(s)$ while the non-AGC generation requirements are described by $P_2(s)$.

The result will be a frequency domain transfer function as shown in Figure 7(a). Depending on the characteristics of the different generators, and their cost curves, the ISO should procure the lowest-cost combination of resources that meet the frequency domain requirements for operating reserves. This process is illustrated in Figure 7(b) and described in greater detail in [54]. In reality, each frequency band will be satisfied with a combination of resources.

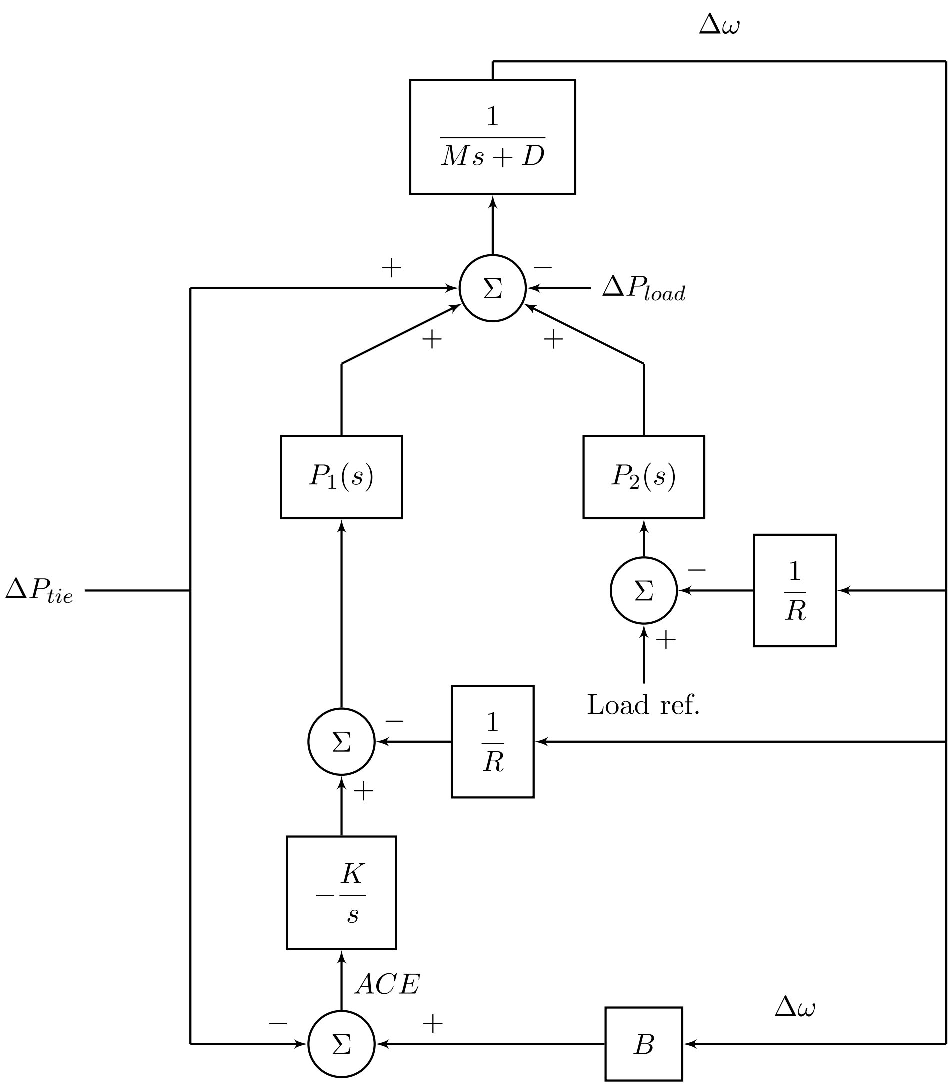
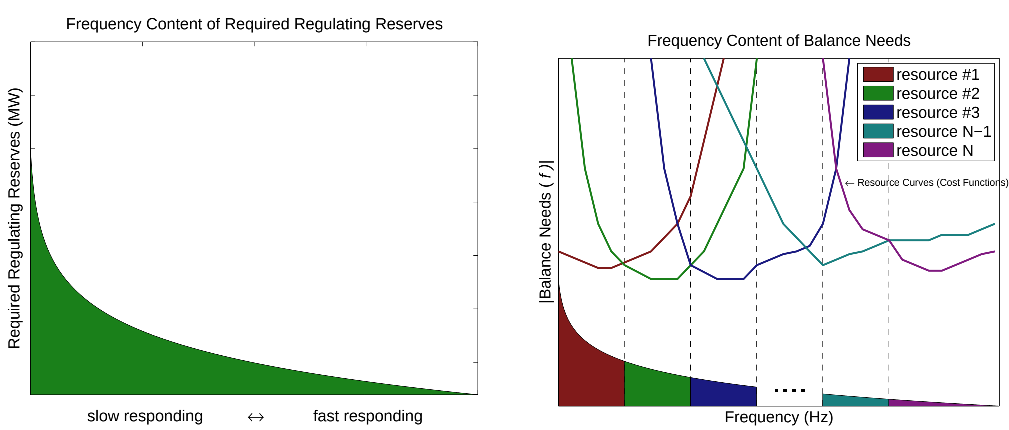


Figure 6: Simplified Area System Model.



(a) Frequency Domain Operating Reserve Requirements.

(b) Allocation to Optimal Resources.

Figure 7: Notional Frequency Domain Transfer Function of Required Operating Reserves.

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