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Market Design for the Simultaneous Optimization of the Day-Ahead Market and the Reliability Unit Commitment Applications

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Abstract

The design of restructured electricity markets requires a mechanism to ensure that differences between the bid-in demand that clears in the Day-Ahead Market (DAM) and the ISO's demand forecast do not compromise reliability requirements. This mechanism is usually called Reliability (or Residual) Unit Commitment (RUC), and is deployed to procure additional resources, beyond the DAM energy schedules, to meet the demand forecast. In this paper, we present the theoretical foundation of the RUC process and key important considerations in implementing the RUC application. We also provide a description of the general sequential approach in which the DAM application is executed first and then the RUC process is completed. We then offer the design framework for the implementation of an integrated approach which combines the functionality of the DAM and the RUC into one market application. The integrated approach offers substantial efficiencies by procuring all DAM products simultaneously.

Index Terms — Day-Ahead Market, Reliability Unit Commitment, Real-Time Market, Ancillary Services, Locational Marginal Pricing, Security Constrained Unit Commitment.

Nomenclature

Parameters/Variables:

B	As-bid benefits (refers to demand)
C	As-bid costs
F	Flow
P	Price bid
Q	Quantity
SF	Shift Factors

Subscripts/Superscripts:

AS	Ancillary Services
DF	Demand Forecast of the Non-Participating Load
En	Energy
EXP	Export
G	Generation Units that bid or self-schedule
IMP	Import (bids for energy or ancillary services)
ML	Minimum Load
NPL	Non-Participating Load
RUC	Reliability Unit Commitment capacity bids
PL	Participating Load
Rcap	Resource capacity
Req	Requirements
SU	Startup

I. Introduction

Independent System Operators (ISOs) clear the Day-Ahead Market (DAM) by deploying the bid-in demand which in general is different than next day's peak load for various reasons. Therefore, it is possible that the scheduled load in the DAM may be significantly lower than the demand forecast, resulting in insufficient resources with long startup times committed in the DAM to meet next day's peak load. For this purpose, the ISOs deploy a process, called Reliability (or Residual) Unit Commitment (RUC), for committing adequate resources to meet the peak load in each hour of the next day, the Trading Day. Consequently, the objective of the RUC is to commit resources that would otherwise not be committed by the DAM application. The fundamental methodology for solving the RUC problem is based on the Security Constrained Unit Commitment (SCUC) that is also used in clearing the forward markets. Both the DAM and the RUC processes require multi-part offers (startup, minimum-load, incremental energy bids for DAM and RUC capacity availability bids for RUC) and consider all system and resource constraints along with all transmission constraints in developing a least-cost commitment and dispatch for a 24-hour period (which can be extended to several days ahead).

The objective function of the RUC optimization is to minimize the total bid-in costs as reflected by the startup, cost, minimum load cost and the capacity availability bids, in lieu of energy bids, submitted at the same time as the other DAM bids. This architecture has been adopted by the California ISO [1]. However, in other markets [2,3] the RUC process minimizes mainly or entirely the startup and the minimum-load cost components for additional commitments. Specifically, in the FRAC (Day-Ahead RUC) process, the MISO deploys a 0.001 multiplier on the energy curve (above the economic Minimum). This is exactly what ERCOT does as well. This factor allows the RUC process to dispatch units around a constraint, but it minimizes the impact on the objective cost.

This is motivated by the goal of minimizing the uplift costs resulting from startup and minimum load prices, as well as creating incentives for market participants to submit bids and offers as accurately as possible in the DAM. However, this objective may give an advantage to imports in the dispatch process (since they do not have startup and minimum load bid components) as compared to generators inside the ISO region (which do have startup and minimum load bids). This bias could result in inefficient market outcomes if the energy from imports is not really needed in real-time. This is the reason markets that rely on imports in a substantial way, like California, do not favor this objective option. On the other hand, generators selected in the RUC process that are dispatched at their minimum block can also contribute to uplift costs if their unit commitment costs exceed the Location Marginal Price (LMP). In summary, this objective option leads to lower procurement costs, but does not result in RUC marginal prices with locational attributes.

In this paper, we present the design framework for the implementation of an integrated approach which combines the functionality of the DAM and the RUC into one market application. In Section II we present the theoretical foundation of the RUC process and the key important considerations in implementing RUC, including pricing and other practical issues. We also provide a description of the general sequential approach (which dominates the current market architecture in all markets) under which the DAM process is executed first and then the RUC process is completed. In Section III the simultaneous integrated approach is described. In Section IV we present the market design of the integrated simultaneous co-optimizing the DAM and the RUC processes, including the pricing methodology of all the DAM commodities, energy, ancillary services (AS), and RUC capacity and a numerical example. The key contribution of the paper is the development of the framework for the simultaneous co-optimization of the market and the reliability functions. Finally, in Section V we summarize our conclusions.

II. The Sequential Approach

A. Overview and Analysis

Both the DAM and the RUC applications deploy the same network model and enforce the same system and resource constraints. Energy and Reliability schedules are constrained by separate linearized network constraints (for both base case and contingencies) derived from separate AC power flow solutions. Also they both deploy a Security Constrained Unit Commitment. However, RUC enforces three additional types of constraints: 1) Capacity constraints; 2) Energy constraint; and the 3) Quick-Start Resource constraint.

The capacity constraints ensure that sufficient RUC capacity is procured to meet the demand forecast. This is done by enforcing the power balance between the total supply (which includes DAM energy schedules and RUC capacity) and the total demand (which includes DAM export schedules and the forecast.) The demand forecast can be manually adjusted by the ISO to increase the RUC target if there is any ancillary services (AS) bid insufficiency in DAM or for other reasons.

The energy constraint ensures that RUC will not commit excessive amount of minimum load energy from internal resources. Specifically, the constraint ensures that the sum of the DAM energy schedules (generators and imports), the DAM energy schedules of load reductions of participating loads and the minimum load energy committed by RUC will not be greater than a configurable percentage (e.g., 95%) of the demand forecast.

Finally, the Short-Start Resource constraint ensures that RUC will not commit excessive amount of capacity from Short-Start Resources (depleting this valuable resource from commitments in downstream markets). Specifically, the constraint ensures that the total DAM energy schedules and RUC capacity from Short-Start Resources is not greater than a configurable percentage of the total available capacity of all Short-Start Resources.

With respect to the execution sequence of the market (DAM) and reliability (RUC) applications there are two distinct options. In the first option the DAM-RUC sequence is adopted where the DAM is executed first and then is followed by the RUC. In this option, a resource cannot skip the DAM to participate in the RUC market directly; the total amount of RUC award is limited by the quantity of the energy bid minus the sum of DA energy schedule and the upward AS awards. In other words, the sum of the DA energy schedule, the upward AS awards including ancillary self-provisions, and the RUC award is limited by the quantity of the energy bid.

In the DAM-RUC sequence, resources that are committed in the DAM are modeled in RUC as "Must-Run" and the AS schedules that cleared the DAM are fixed. In this sequence, the RUC may commit additional resources to cover the difference between the demand forecast and the scheduled energy in the DAM. RUC capacity awards are the incremental amount of capacity above the DAM energy schedules, which are needed to meet the demand forecast in the RUC optimization. The ISO will only issue RUC instructions to resources that must be started in day ahead in order to be available to meet real-time load. In other words, the ISO will re-evaluate the commitment decisions in the Hour-Ahead Market (HAM) for resources that can be started in the HAM process. Therefore, under this design, RUC is an incremental process that runs sequentially and on top of the DAM process, i.e. the DAM unit commitment is protected in the RUC process.

In the second option the RUC-DAM sequence is adopted where the RUC is executed first and then is followed by the DAM. In the RUC-DAM sequence, the resources committed by the RUC define the pool of resources that can be committed in the DAM; resources with inter-temporal constraints that are not committed in the RUC are ignored in the DAM.

The DAM-RUC sequence yields the most efficient outcome for the DAM since the DAM solution is not restricted; therefore this option is optimal for DAM. RUC may commit more units but DAM units have a Must Run status (enforced by penalty functions) therefore, overall, there is some loss of efficiency. Further, in this case the minimum load energy from units committed in RUC is not included in DAM. Some ISOs have resolved this problem by executing the DAM again after the RUC is completed in order to price the RUC induced minimum energy [4].

The RUC-DAM sequence may result in the best commitments for the Real-Time Market (RTM). However, with this option, DAM works only with the pool of units committed in RUC. This may result in a loss of efficiency for the DAM. Also, the energy committed at the Minimum Load in RUC may depress the DAM prices, thus providing incentives to load not to under-schedule. However, a key disadvantage of this option is that it makes it very difficult to distinguish the additional resource commitment cost required for cost allocation, cost causation and incentive purposes. This is important because the ISOs keep track of the unit commitment costs incurred in RUC; these costs are recovered by the Market Participants who cause the additional commitments.

All current operational markets have adopted the DAM-RUC sequence architecture [1-6].

B. Price Setting Mechanism

If the RUC process deploys capacity availability bids, the RUC optimization produces RUC LMPs. A resource that receives a RUC instruction will be compensated by the product of the RUC capacity award and the RUC LMP of its location. The determination of the RUC LMP is similar to the determination of the energy LMP, except that RUC capacity bids are used for the RUC LMP calculations. Although RUC providers are paid by the RUC LMP, the costs incurred by the ISO for procuring the RUC capacity is allocated to load on a system-wide basis. Specifically, the RUC cost allocation uses a 2-tier settlement approach. The first tier settlement allocates a portion of the RUC cost to the load deviations. The second tier settlement allocates the remaining RUC cost to all loads on a system wide basis. This approach prevents over-charging the Market Participants in case of large demand forecasting errors by the ISOs.

If the RUC process deploys only startup and minimum-load bid costs (but not RUC capacity availability bids or energy bids), the RUC optimization does not produce LMPs. In this case a resource that receives a RUC instruction will only receive its commitment costs.

For pricing purposes, we also distinguish between two distinct options. Under the first option (DAM-RUC), prices in the DAM are set prior to the RUC process. Under the second option (DAM-RUC-DAM), prices are set after the RUC process. Under either option, the price in the DAM is set based on bid-in load. The difference lies in what set of supply is considered in setting the price for the DAM. Under the first option, prices in the DAM are set without regard to what happens in the RUC process (the "PJM approach") [5]. Under the second option, the DAM price is set after the RUC process (by executing another DAM run) at possibly a lower level (the "NYISO approach") [4].

Consider an example where the DAM clears 10,000 MW at a price of 50 \$/MWh (assuming prices are set prior to the RUC process). If the ISO's demand forecast is 10,500 MW, the RUC process would test whether it would be possible to meet the 500 MW of load with existing resources. If this is not possible, RUC would need to commit additional resources to meet the 500 MW of forecasted demand. Assume a 500-MW unit with a minimum output of 50 MW is committed.

Under the first approach (DAM-RUC), the resources that may be rarely backed down (even though they are protected by penalty functions), they would be paid their opportunity costs, just as a spinning reserve unit might expect when it is backed down in the energy market. The opportunity costs would be measured based on the DAM price of 50 \$/MWh, which was already set prior to the RUC. Under the PJM approach the schedules are set prior to the RUC, and the RUC capacity is simply committed.

Under the second approach (DAM-RUC-DAM), the 50 MW of RUC "Must-Run Generation" would displace 50 MW of resources already committed in the DAM. However, the price in the DAM would be set after this adjustment is made at a level that is most likely less than 50 $/MWh. The NYISO follows this approach [4].

The California ISO market architecture is consistent with the PJM approach, i.e. prices are set based on the DAM before running RUC. However, the DAM unit commitment is protected from changes in the RUC run. If the RUC commits additional resources and backs down DAM schedules, the ISO will schedule the DAM schedules as determined by the DAM not by the RUC.

Nevertheless, relaxation of the constraints that protect the DAM unit commitment may result in lower total procurement costs if a simultaneous optimization is performed that combines the DAM and the RUC processes. We discuss the integrated simultaneous DAM-RUC optimization approach in the following Section.

In summary, the current sequential market architecture results in suboptimal solutions in the forward spot market because it is achieved in two stages. Further, each stage deploys a different objective and the commitment of the first stage (DAM) is locked in the second stage (RUC). This architecture, results in higher costs since additional resource commitments may occur in RUC that would not have occurred if an integrated approach based on a simultaneous co-optimization had been adopted.

III. The Integrated Simultaneous Approach

The integrated approach, based on the simultaneous optimization of the DAM and the RUC processes, will result in lower total procurement costs and more efficient commitment of resources to meet both scheduled and forecasted demand and provide the required reserves. This is particularly true when the optimization must include RUC capacity availability bids in addition to start-up and minimum load bids. Further, the integrated approach will also result in more efficient procurement of ancillary services (AS) because the pool of available resources for AS will also include RUC resources (which under the sequential approach are not identified until after the DAM AS procurement is completed). The size and complexity of the simultaneous co-optimization problem, however, will increase as shown in the following Section.

The objective of the combined DAM/RUC process is to minimize the overall bid-in costs subject to transmission as well as resource related constraints over the entire time horizon. The overall cost is determined by:

a) Startup cost of committed resources;
b) Minimum load cost of committed resources;
c) Energy curve bids/offers;
d) AS capacity bids (of various types); and
e) RUC capacity availability bids (or energy bids as an alternative).

It should be noted that the RUC capacity is different than the ISO's operating reserve service that is zonally procured in the DAM. The objective of the operating reserves is to support the system when forced outages occur. It is uncertain beforehand if these reserves will, or can, be dispatched in real time. Since the location of forced outages is not known in advance, the ISO may experience situations where the procured AS reserves were available but they could not be called upon due to the presence of intra-zonal congestion in real-time [7].

The RUC capacity, on the contrary, is determined based on the ISO’s demand forecast projected at the nodal level and procured during the DAM/RUC process. Since the RUC capacity is based on the forecasted demand, it has a high probability to be dispatched in real-time assuming that the ISO’s demand forecast is reasonable. Moreover, the security analysis in the RUC unit commitment will verify that the RUC capacity can be dispatched to meet the demand forecast while maintaining reserves. Therefore, the RUC capacity represents a physical commitment from the selected resources to provide a reliability reserves service.

IV. Market Design of the Integrated Simultaneous DAM/RUC Optimization

In this Section the market design of the integrated simultaneous DAM/RUC optimization is proposed. A methodology that deploys one pricing run to determine energy/AS prices and RUC capacity prices is also presented.

Under the integrated combined DAM/RUC approach, the scheduled energy is procured only to satisfy the bid-in demand that clears in the DAM. RUC capacity is additionally procured to satisfy the system demand forecast. It must be possible to both dispatch resources to meet bid-in demand and to dispatch resources to meet the demand forecast while respecting all resource, transmission and other reliability constraints.

The AS procurement under the integrated combined DAM/RUC approach is performed in the standard way. The procurement is based on regional AS requirements and AS cascading is allowed.

The load entities are classified into the following categories:

a) Participating Loads (PL) with priced load bids; these are not included in system demand forecast;

b) Nonparticipating Loads (NPL) which are considered price-taking loads; their schedules are included in the system demand forecast;
c) Demand forecast (DF); this is the ISO's demand forecast for the NPL.

All physical loads are considered on an individual basis in the Power Flow calculations and for congestion management. Load Distribution Factors are deployed to disaggregate the load on the bus level.

The objective function of the simultaneous optimization in the scheduling run minimizes the overall cost including startup costs, minimum load costs, energy bids, AS capacity bids, and RUC capacity availability bids to satisfy bid-in load and the value of unmet bid load (PL, NPL) and the demand forecast. Also, transmission line and resource capacity constraints are observed.

Virtual generation and virtual load bids for energy can also be part of the integrated simultaneous DAM/RUC optimization. By submitting a virtual bid, the participants bid to take a forward financial position at a specific grid location which will be liquidated in real time at real time prices. However, for simplicity and without loss of generality we shall not consider virtual bids in this paper.
In the following we present a generic formulation of the integrated DAM and RUC process. We distinguish between the scheduling run and the pricing run(s). We also provide a numerical example which illustrates the benefits of the proposed methodology.

A. Energy/AS and RUC Scheduling (Simultaneous)

1) Objective Function. The overall market operating costs are minimized based on the following objective function:

$$\text{minimize}\begin{Bmatrix} C_G^{En} + C_G^{SU} + C_G^{ML} + C_{IMP} - B_{PL}^{En} - B_{EXP} \\ + C_{AS} + C_{RUC} \end{Bmatrix} \tag{1}$$

The PL and EXP bids are positive numbers and are subtracted in the objective function so that the objective function is minimized when these quantities are maximized. For simplicity by C (B) we denote the sum of the costs (benefits) for all resources in the optimization horizon (e.g. 24 hours).

2) Constraints. In the scheduling run the following constraints are considered.

<u>Power Balance Constraints</u>: For the power balance, we consider the following two equations.

The first power balance equation is the market energy balance that includes all energy schedules. The bid-in and self-scheduled generation (G), Non-Participating Loads (NPL) and Participating Loads (PL), energy imports (IMP) and exports (EXP) should be balanced. For simplicity we did not consider the network losses. By Q we denote the sum of quantities for all resources at a given Trading Hour. Therefore, the first power balance equation is as follows:

$$Q_G + Q_{IMP} = Q_{PL} + Q_{NPL} + Q_{EXP} \tag{2}$$

For example, suppose that we have:

$Q_G = 10{,}000\,\text{MW}$; $Q_{IMP} = 100\,\text{MW}$; $Q_{PL} = 500\,\text{MW}$; $Q_{NPL} = 9{,}500\,\text{MW}$; $Q_{EXP} = 100\,\text{MW}$.

Then,

$$\begin{aligned} Q_G + Q_{IMP} &= 10{,}000 + 100 = \\ &= Q_{PL} + Q_{NPL} + Q_{EXP} = \\ &= 500 + 9{,}500 + 100 = 10{,}100\,\text{MW}. \end{aligned}$$

Additional RUC capacity should be committed to cover the gap between the bid-in demand and the demand forecast. Therefore, the second power balance equation is as follows:

$$Q_G + Q_{IMP} + Q_{RUC} = Q_{PL} + Q_{DF} + Q_{EXP} \tag{3}$$

In the previous example, suppose that the demand forecast load is $Q_{DF} = 12{,}000\text{MW}$. Then the total load would be:

$$\begin{aligned} \text{Total Load} &= Q_{PL} + Q_{DF} + Q_{EXP} = \\ &= 500 + 12{,}000 + 100 = 12{,}600\,\text{MW}. \end{aligned}$$

Therefore:

$$Q_{RUC} = 12{,}600 - 10{,}100 = 2{,}500\,\text{MW}.$$

Note that in our example, we can equivalently rewrite (3) as a RUC capacity requirements constraint as follows:

$$Q_{RUC} = Q_{FL} - Q_{NPL} \tag{4}$$

<u>Transmission Constraints</u>: We now list the two sets of equations that represent the transmission constraints, one for the market energy power balance and one for the physical power balance that includes the RUC terms. The network deployed in both sets of transmission constrained equations is exactly the same. The RUC flows are

constrained in the RUC network; they do not provide counter flows in the DAM network related transmission constraints.

The power flows in both sets of the transmission constraints are calculated by deploying the shift factors, also called the Power Transfer Distribution Factors. The shift factors are calculated for all network connectivity nodes in the network with respect to power generation. Therefore each resource at the same network node should have the same shift factor. The load shift factors are equal to negative generation shift factors at the same node. Wheeling schedules are also contributing to the network line flows, but they are not modeled in this formulation for simplicity. F_{base} is the value of the transmission line flow as calculated in the power flow.

The two sets of equations are given as follows:

$$F_{min} \leq F_{base} + \sum_{i} SF_i \cdot \Delta Q_i \leq F_{\max} \tag{5}$$

where ΔQ_i represents incremental energy resources with resource i found in the sets $\mathbf{S_1} = \{G,\ IMP\}$ for supply, and $\mathbf{D_1} = \{PL,\ NPL,\ EXP\}$ for demand;

and

$$F_{min} \leq F_{base} + \sum_{i} SF_i \cdot \Delta Q_i \leq F_{\max} \tag{6}$$

with resource i found in the sets $\mathbf{S_2} = \{G,\ RUC,\ IMP\}$ for supply, and $\mathbf{D_2} = \{PL,\ DF,\ EXP\}$ for demand.

Resource Capacity Constraint: This constraint now includes the reserved RUC capacity, as follows:

$$Q_G + Q_{AS} + Q_{RUC} \leq Q_{Rcap} \tag{7}$$

B. Energy/AS and RUC Pricing

In this Section we present the theoretical foundation for the pricing run required to produce meaningful LMPs for all DAM/RUC commodity products, energy, AS reserved capacity and RUC capacity. We also propose a methodology suitable for the integrated DAM/RUC simultaneous optimization for the computation of these marginal prices.

1) Overview and Analysis. The integrated SCUC optimization engine, which will solve the combined DAM and RUC problems, will produce schedules and LMPs for every time interval of the time horizon for all the DAM/RUC commodity products. However, in the event that resources are optimally scheduled or dispatched in the penalty region due to "uneconomic adjustments" required for feasibility, marginal prices would reflect the penalty prices of marginal resources scheduled or dispatched in the penalty region. Similarly, if binding constraints are violated for feasibility, marginal prices would reflect the penalty prices for these violations.

The solution to this problem requires another run, called the “pricing run,” to “filter” these penalty prices out of the dual solution (which produces the prices). Specifically, resources scheduled or dispatched in the penalty region outside their energy bid (or their schedule if there is no energy bid) will be scheduled or dispatched optimally based on specified configurable priorities, but the appropriate bid cap shall be used for pricing purposes. For supply increase or demand decrease in the penalty region the energy bid ceiling (bid cap) will be deployed. For supply decrease or demand increase in the penalty region the energy bid floor will be deployed.

Also, resources that are not allowed to set the marginal price should also be filtered out in the pricing run. Specifically, in the pricing run these schedules and dispatches should be fixed and not re-optimized.

To maintain consistency between DAM/RUC resource scheduling and commodity pricing, the optimal solution of the combined DAM/RUC scheduling run is preserved in the pricing run to the maximum extent possible. The resource commitment statuses from the combined DAM/RUC scheduling run are locked in the pricing run, i.e. committed units would be "must run" and uncommitted units would be "must not run". All other constraints shall be considered in the pricing run. Also, energy self-schedules that have not been adjusted in the combined DAM/RUC scheduling run are considered constant in the pricing run.

Specifically, the optimal resource schedules are bounded with very narrow artificial bounds in the pricing run around the optimal solution of the combined DAM/RUC scheduling run if they were scheduled in the penalty region. The bounds should be large enough to allow a feasible region without creating degeneracy of the optimization model. All other resources, are bounded by their original operating limits in the pricing run. Special arrangements are made for the "Constrained Output Generators" to ensure consistency of between schedules and prices to the maximum extent possible.

2) Proposed Single Pricing Run Methodology. Under the single pricing run approach LMPs are derived directly from the co-optimization for both DAM and RUC variables simultaneously. If there is not enough capacity to meet the demand forecast, there will be scarcity reflected in higher RUC LMPs.

In what follows, we provide a basic simplified formulation for the single (simultaneous) pricing approach for the integrated simultaneous DAM/RUC problem. For illustration purposes, we simplify the problem and we consider one node, with no imports/exports and no losses. The load is considered to be only NPL-type. For simplicity, we also assume one AS type in the upwards direction. We denote with s the dispatched supplier (generator) and with h the dispatching hour.

We now rewrite the objective function (1) assuming that the optimal commitment is found (by the combined DAM/RUC scheduling run).

$$\text{minimize} \left\{ \sum_{s,h} P_{s,h}^{G} \cdot Q_{s,h}^{G} + \sum_{s,h} P_{s,h}^{AS} \cdot Q_{s,h}^{AS} + \sum_{s,h} P_{s,h}^{RUC} \cdot Q_{s,h}^{RUC} \right\} \tag{8}$$

subject to:

<u>Power Balance Constraint:</u>

$$\sum_{s} Q_{s,h}^{G} = Q_{h}^{NPL} \qquad \forall h \tag{9}$$

<u>AS Constraints:</u>

$$\sum_{s} Q_{s,h}^{AS} \geq Req_{h}^{AS} \qquad \forall h \tag{10}$$

<u>RUC Constraints:</u>

$$\sum_{s} Q_{s,h}^{RUC} \geq Req_{h}^{RUC} (= Q_{h}^{DF} - Q_{h}^{NPL}) \qquad \forall h \tag{11}$$

<u>Resource Capacity Constraints:</u>

$$Q_{s,h}^{G} + Q_{s,h}^{AS} + Q_{s,h}^{RUC} \leq Q_{s}^{RCap} \qquad \forall s,h \tag{12}$$

Under this simultaneous pricing approach, the shadow prices of constraints (9)-(11) define the marginal prices for energy, AS, and RUC capacity. Resources that do not recover their as-bid costs are eligible for some sort of bid/cost recovery mechanism to ensure their revenue sufficiency guarantee.

Finally, it is important to note that the integrated DAM/RUC simultaneous optimization creates a cost allocation problem. Specifically, the current Bid Cost Recovery (BCR) allocation methods for DAM and RUC track unrecovered unit commitment costs separately and allocate them using a different methodology. However these costs cannot be distinguished in the integrated DAM/RUC optimization. Further research is required to distinguish and allocate the unrecovered costs in the proposed integrated approach properly.

C. Numerical Example

To illustrate the benefits of the proposed integrated approach we deploy a 10-unit actual system taken from the Greek electricity market [8, Section II]. The full optimization model for this example is presented in [9, Section II]. For the needs of our analysis we make the following adjustments.

We assume that the market load is 95% of the demand given in [8, Table III] and that the forecasted demand is 300 MW higher than the market load. We also assume that the startup cost is properly represented in the objective function (i.e. we do not use the particularity of the Greek market which exchanges the startup and shutdown costs). Lastly, we assume that the units submit reserve bids that are equal to 5€/MW per hour and RUC capacity bids that are equal to 3€/MW per hour.

The results in terms of system cost for the two cases, i.e. the sequential DAM-RUC approach and the simultaneous approach, verify that the simultaneous approach leads to lower system cost, with a difference of €5,719 for this daily run. Since both approaches solve the same optimization problem, the two-stage (sequential) approach is bounded by the optimal result that is found if the problem is solved in a single stage (simultaneous approach). If it happened that the unit commitment obtained at the first stage was part of the optimal (least cost) commitment, then the two approaches would be equivalent.

We also note that, in the specific example, the commitment cost under the simultaneous approach is higher than the respective cost under the sequential approach, with the difference of €8,000; the sequential approach does not commit unit U8 (startup cost €50,000), whereas the simultaneous approach does not commit units U6 and U9 (startup costs €18,000 and €24,000 respectively). However, the energy generation cost is lower by €13,719, which results in the aforementioned decrease of the total system cost by €5,719.

Lastly, we observe that the sequential approach generally leads to higher energy and reserve prices. We recall that these prices are obtained by the first stage in the sequential approach, which does not take into account the increased forecasted demand and generally results in less units committed and hence lower amounts of minimum-load capacity. The energy and reserve prices under both approaches are shown in Fig. 1.

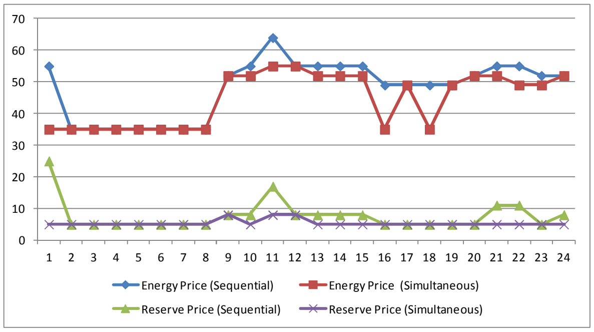

Fig. 1. Energy and reserve prices (vertical axis in €/MW; horizontal axis in hours).

From the demand (consumer) perspective, the lower energy prices in the day-ahead market lead to an average reduction of about 3.5€/MWh. The cost for reserve if allocated to the load (as an uplift) is also lowered by 0.3€/MWh. Nevertheless, we note that the lower energy prices lead to increased make-whole payments, the difference being around 1€/MWh.

In our ongoing work on this subject, we plan to perform extensive simulations on large realistic test cases that include transmission constraints to quantify and evaluate the impacts of the proposed approach on system costs, and overall market efficiency.

V. Conclusions

In this paper we present the theoretical foundation of the Reliability (or Residual) Unit Commitment (RUC) process and key important considerations in implementing the RUC application. We also provide a description of the general sequential approach in which the Day-Ahead Market (DAM) application is executed first and then the RUC process is completed. Further, we propose an integrated approach which combines the functionality of the DAM and the RUC into one market application. The integrated approach which is based on the simultaneous optimization of the two problems offers efficiencies and lower market procurement costs by procuring all DAM products simultaneously, including energy, Ancillary Services and RUC capacity while respecting all system and generation resource constraints. It also ensures that both DAM energy and Ancillary Services schedules and RUC reliability capacity awards are physically feasible with respect to all constraints. The integration of the market and the reliability functions in the forward spot market is considered a major improvement compared to the current market architectures.

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VII. Biographies

Alex D. Papalexopoulos (M'80–SM'85–F'01) is CEO and founder of ECCO International, a specialized Energy Consulting Company which provides consulting and software services on electricity market design, system operations and planning worldwide to a wide range of clients such as Regulators, Governments, Utilities and ISOs. Over the last 20 years he has been heavily involved in the design and implementation of some of the most complex energy markets in the world. Prior to forming ECCO International he was a Director of the Electric Industry Restructuring Group at the Pacific Gas and Electric Company in San Francisco, California. He has published numerous scientific papers in IEEE and other scientific Journals and has given numerous invited presentations in leading institutions.

Dr. Papalexopoulos is a Fellow of IEEE, the 1992 recipient of PG&E's Wall of Fame Award, and the 1996 recipient of IEEE's PES Prize Paper Award. He received the electrical engineering Diploma from the National Technical University of Athens, Greece, and the M.S. and Ph.D. degrees in electrical engineering from the Georgia Institute of Technology, Atlanta Georgia. He is also the CEO and Chairman of the Board of ZOME Energy Networks, an energy software company which specializes in the research, development and commercialization of smart grid and demand response management technologies.

Panagiotis E. Andrianesis graduated from the Hellenic Military Academy (2001), received his B.A. (2004) degree in economics from the National and Kapodistrian University of Athens, and his Diploma (2010) in electrical and computer engineering from the National Technical University of Athens. He received his M.Sc. (2011) degree in production management from the University of Thessaly, Volos, Greece, where he is currently a doctoral student. His research interests include power systems economics, electricity market design and optimization. Mr. Andrianesis is also a consultant associated with ECCO International.

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