Deliverable Robust Ramping Products in Real-Time Markets

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***Abstract*—The increasing penetration of variable energy resources has led to more uncertainties in power systems. Flexible Ramping Products (FRP) have been adopted by several electricity markets to manage the uncertainties. We reveal that neglected line congestion for FRP may not only cause infeasibility, but also result in a failure of cost recovery. To address the deliverability issues on FRP, this paper proposes a new concept, Deliverable Robust Ramping Products (DRRP), in real-time markets. The DRRP includes generation ramping reserve and generation capacity reserve. The DRRP is deliverable and immunized against any pre-defined uncertainty. It also fully addresses the bid cost recovery issue caused by the line congestion in existing FRPs. The prices of DRRP are derived within the Affine Adjustable Robust Optimization (AARO) framework. These prices can be used to identify valuable reserves among available reserves and quantify the values of flexible resources that provide reserves. This paper also proposes a general approach to obtaining the time-decoupled prices for DRRP and generation, which can be used for the market settlement of the first interval only in real-time markets. Simulations on a 3-bus system and the IEEE 118-bus system are performed to illustrate the concept of DRRP and the advantages of DRRP compared to existing FRP.**

***Index Terms*—Ramping Reserve, Capacity Reserve, Marginal Price, Ramping Products, Robust Optimization**

Nomenclature

Indices

i, k, l, t	index for unit, uncertainty, line, and time
m, n	index for bus

Notations and sets

$\mathbb{R}^x$	the set of real x-vectors
$\mathbb{R}^{x \times y}$	the set of real $x \times y$ matrices
$\mathcal{L}(\cdot)$	Lagrangian function
$(\cdot)^*$	optimal value of a variable
$C(\cdot)$	cost function
$\mathcal{G}(m)$	set of units located at bus m

Constants

N_b, N_g, N_l	number of buses, units, and transmission lines
N_k	number of uncertainty constraints
T	number of time intervals
δ	timespan of one interval (minutes)
$d_{m,t}, \boldsymbol{d}$	aggregated equivalent load demand at bus m at t, $\boldsymbol{d} = [d_{1,1} \cdots d_{N_b,T}]^\top$
$\bar{F}_l, \boldsymbol{F}$	branch flow limit, abstract vector $\boldsymbol{F} \in \mathbb{R}^{2N_lT}$
$\Gamma_{l,m}$	shift factor for line l and bus m
$P_i^{\min}, P_i^{\max}$	minimum and maximum generation outputs
$R_i^{\text{up}}, R_i^{\text{down}}$	unit ramping up/down limits (MW/minute)
$\boldsymbol{D}$	time-load incidence matrix, $\boldsymbol{D} \in \mathbb{R}^{T \times N_bT}$
$\boldsymbol{A}, \boldsymbol{R_i}$	abstract matrix and vector for (4)-(6), $\boldsymbol{A} \in \mathbb{R}^{4T \times T}$, $\boldsymbol{R_i} \in \mathbb{R}^{4T}$.
$\boldsymbol{\Gamma_i}, \boldsymbol{\Gamma_d}$	abstract shift factor matrix for unit i and load
$\boldsymbol{S}, \boldsymbol{h}$	polyhedron uncertainty set matrix and vector

Variables

$\boldsymbol{G_i}$	generation adjustment matrix, $\boldsymbol{G_i} \in \mathbb{R}^{T \times N_bT}$
$\boldsymbol{\pi}$	prices. $\boldsymbol{\pi}_{\boldsymbol{i}}^{\text{e}}$ is the energy LMP for unit i, $\boldsymbol{\pi}_i^{\text{e}} \in \mathbb{R}^T$; $\boldsymbol{\pi}_i^{\text{r}}$ is the reserve price vector for unit i, $\boldsymbol{\pi}_i^{\text{r}} \in \mathbb{R}^{4T}$.
$P_{i,t}$	generation output, $P_{i,t} \in \mathbb{R}$
$\boldsymbol{P_i}$	generation vector, $\boldsymbol{P_i} = [P_{i,1} \cdots P_{i,T}]^\top \in \mathbb{R}^T$
$\hat{\boldsymbol{P}}_i$	generation re-dispatch vector, $\hat{\boldsymbol{P}}_i \in \mathbb{R}^T$
$Q_{i,t}^{\text{r,u}}, Q_{i,t}^{\text{r,d}}$	generation ramping reserve, $Q_{i,t}^{\text{r,u}} \in \mathbb{R}, Q_{i,t}^{\text{r,d}} \in \mathbb{R}$
$Q_{i,t}^{\text{c,u}}, Q_{i,t}^{\text{c,d}}$	generation capacity reserve, $Q_{i,t}^{\text{c,u}} \in \mathbb{R}, Q_{i,t}^{\text{c,d}} \in \mathbb{R}$
$Q_{i,t}^{\text{FRP,u}}$	upward ramping products in the existing FRP model, $Q_{i,t}^{\text{FRP,u}} \in \mathbb{R}$
$Q_{i,t}^{\text{FRP,d}}$	downward ramping products in the existing FRP model, $Q_{i,t}^{\text{FRP,d}} \in \mathbb{R}$
$Q_{\text{Req},t}^{\text{FRP,u}}$	upward ramping requirement in the existing FRP model, $Q_{\text{Req},t}^{\text{FRP,u}} \in \mathbb{R}$
$Q_{\text{Req},t}^{\text{FRP,d}}$	downward ramping requirement in the existing FRP model, $Q_{\text{Req},t}^{\text{FRP,d}} \in \mathbb{R}$
$\boldsymbol{\epsilon}, \epsilon_{m,t}$	uncertainty vector and uncertainty at bus m at t, $\boldsymbol{\epsilon} \in \mathbb{R}^{T \times N_b}, \epsilon_{m,t} \in \mathbb{R}$
$\boldsymbol{\lambda}, \boldsymbol{\alpha_i}, \boldsymbol{\eta}$	Lagrangian multipliers for constraints (18,20,22)
$\boldsymbol{\gamma}, \boldsymbol{\beta_i}, \boldsymbol{\tau}$	Lagrangian multipliers for constraints (19,21,23)
Θ_i	credits to uncertainty mitigator i

I. Introduction

THE renewable energy sources (RES), such as wind power generation, and price-sensitive demand response (DR) have attracted a lot of attentions recently. The total installed capacity of wind power in the U.S. reached 47 GW at the end of 2011 [1]. Several ISOs/RTOs, such as PJM, ISO New England, NYISO, and CAISO have initiated DR programs in their markets [2]. The essential objective to use renewable energy and initiate DR programs in electricity markets is to maximize the market efficiency as well as to protect the environment. However, they also pose new challenges to the system operators in electricity markets. Due to its intrinsic characteristics, it is sometimes hard to accurately predict the amount of available renewable energy. For instance, large-scale wind production varies from -20% to 20% of the installed

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wind capacity in Denmark on an hourly basis [3]. Prediction error for aggregated wind farm output by existing state-of-the-art method may range from 5% to 20% of the total installed capacity [4]. In the meantime, the amount of un-predictable loads also increases in the wholesale market as the forecasting of price-sensitive loads relies on the forecasted price as input, which itself has significant error.

Surviving uncertainties is fundamentally important for the reliable and secure operation of a power system. If the system with pre-planned schedule cannot follow the deviation of the wind power and load, the system operator may have to curtail wind energy or shed load in the real-time market (RTM). In order to maintain the reliability of the system, the ISO/RTO has to increase the ramping capability of the system to compensate the variations of wind energy and load in a short time [5], [6]. More efficient and reliable methods are required to determine the optimal reserves when the uncertainty level is high. Recently stochastic and robust approaches are proposed to address the issues related to uncertainties in electricity markets. At the same time, market designers are also seeking effective market mechanism to address the uncertainty issues. For instance, intraday market (IDM) is now established between day-ahead market (DAM) and RTM in European countries since uncertainties on the intraday level are significantly smaller compared to those on the day-ahead level [7]. In the U.S., hour-ahead scheduling process (HASP) is employed by the California ISO [8].

Typical approaches to solving stochastic SCUC are scenario based [9], [10]. The basic idea is to generate enough samples for uncertain parameters with an assumption of their probability distribution function (PDF). Those samples are then modeled in a Mixed Integer Linear/Quadratic Programming (MILP/MIQP) problem. The two main drawbacks of the scenario-based approaches are that it is hard to obtain accurate PDF in some circumstances, and uncertainty accommodation is not guaranteed. In the meantime, the MILP/MIQP problem becomes intractable when the sample size is large. Compared to stochastic optimization, the two largest merits of robust optimization are that the solution can be immunized against all uncertainties and PDF is not required. In [11], [12], robust SCUC problem is solved in two stages. The first stage is to determine the unit commitment (UC) solution which is immunized against the worst case with the lowest cost. In the second stage, a feasible solution to SCED is obtained. Affinely adjustable robust optimization (AARO) models are proposed recently [13]–[16]. They employ an affine function to adjust the generation output following the load deviation. Recently, we propose an efficient robust SCUC model with a fast solution approach [17], [18].

Although applying robust optimization in SCUC/SCED receives a lot of attentions from researchers, it still remains a big challenge on how to credit the flexibilities in the U.S. electricity markets within the robust optimization framework. In the existing Ancillary Service (AS) Market, the reserve requirements are determined in advance [19]. The amount of required reserves is generally obtained from a large number of Monte Carlo simulations for the contingencies [20]. With the help of the AARO, those reserves are determined in one shot based on uncertainty information. Then a critical issue is how to price those reserves when there are no explicit reserve requirement constraints. On the other hand, some reserves are free byproducts in the co-optimization approach [19]. They are kept because the market participants want to get the energy profits. Moreover, some reserves are scarce resources due to their deliverability. These observations indicate that not all the available reserves in the system are valuable from the system operator's point of view.

In many countries, electricity markets are still evolving with the challenges of uncertain energy resource and load [21]. Authors in [22] assessed the time-coupled constraints and the length of look-ahead horizon in the market models. The Flexible Ramping Product (FRP) is proposed by California ISO [23] to integrate more renewables and meet the ramping requirements. In 2016, the Midcontinent Independent System Operator (MISO) also deployed a similar ramping capability product [24] based on [25]. Authors in [25] proposed an approach to address the reserve deliverability on a zonal basis considering discrete contingencies. It should be emphasized that bus-level delivery of the ramping capabilities, which is a very challenging issue in theory, is not considered for FRP in [23]–[25]. In addition, these existing FRP normally ignore the feasibility between intervals after the uncertainty accommodation. Similar to the traditional reserves, another challenge of these FRP is how to determine the ramping requirement requirements. This paper tries to propose new ideas to overcome these challenges. The three major contributions of this paper are listed as follows.

1) A new concept, Deliverable Robust Ramping Products (DRRP), is proposed within the AARO SCED framework. DRRP includes generation ramping reserve and generation capacity reserve. The ramping reserve is the unused ramping capability of a generator when part of its ramping capability is "locked" in the SCED schedule. The capacity reserve is the unused generation capacity of a generator. Different from existing ramping products, these reserves are immunized against any uncertainty. To our best knowledge, this is the first time to consider ramping products in the robust optimization framework.
2) The prices for DRRP are derived within the robust co-optimization framework. With the help of the price information, the valuable reserves can be easily identified among the available reserves. The proposed prices also address the energy bid cost recovery issue in the existing FRP due to line congestion.
3) A general approach to obtaining the time-decoupled price signal is also proposed for DRRP. It can be used for settling the first interval only in the real-time market.

The rest of this paper is organized as follows. The AARO SCED is presented in Section II. The DRRP is defined and its marginal price is derived in Section III. Then how to settle the first interval of the RTM is proposed in Section IV. Case studies for the 3-Bus and the IEEE 118-Bus systems are presented in Section V. Section VI concludes this paper.

II. Affinely Adjustable SCED

A. Conventional SCED

In electricity markets, RTOs/ISOs normally operate two markets including DAM and RTM (or balancing market) [26]. The majority of the trades is cleared in DAM via SCUC and SCED [26], and SCED is normally performed periodically in RTM. This paper mainly focuses on the RTM. In RTM, SCED runs over rolling periods and the scheduling time horizon is normally 1-2 hours with each time interval being 5 or 15 minutes. One of the most important tasks of RTM is to balance the system by adjusting unit dispatch and rescheduling fast-start generators. In this section, the conventional SCED used in RTM is presented. The ISOs minimize the bid-based costs based on generation supply offers submitted by market participants (i.e., generators).

$$\min \sum_i \sum_t C(P_{i,t}) \tag{1}$$

The function $C(\cdot)$ can be in quadratic or piece-wise linear form. The objective function (1) is subject to system generation-load balance constraint as formulated in (2). Other constraints, such as system spinning reserve and emission constraints, can also be included [27].

$$\sum_i P_{i,t} = \sum_m d_{m,t}, \forall t \tag{2}$$

The line flow constraints are formulated as

$$-\bar{F}_l \leq \sum_m \Gamma_{l,m} \left[\sum_{i \in \mathcal{G}(m)} P_{i,t} - d_{m,t} \right] \leq \bar{F}_l, \forall l, t. \tag{3}$$

The online unit generation output is subject to the following constraints including unit capacity limits (6) and unit ramping up/down limits (4), (5), where δ is the timespan from t to t+1.

$$P_{i,t} - P_{i,(t-1)} \leq R_i^{\text{up}} \delta, \forall i, t \tag{4}$$
$$-P_{i,t} + P_{i,(t-1)} \leq R_i^{\text{down}} \delta, \forall i, t \tag{5}$$
$$P_i^{\min} \leq P_{i,t} \leq P_i^{\max}, \forall i, t \tag{6}$$

For notation brevity, the SCED problem can be formulated as follows using matrix and vector forms.

$$\min_{\boldsymbol{P_i}, \forall i} \quad \sum_i C(\boldsymbol{P_i}) \tag{7}$$
$$\text{s.t.} \quad \sum_{\boldsymbol{i}} \boldsymbol{P_i} = \boldsymbol{D}\boldsymbol{d}, \tag{8}$$
$$\boldsymbol{A}\boldsymbol{P_i} \leq \boldsymbol{R} \tag{9}$$
$$\sum_{\boldsymbol{i}} \boldsymbol{\Gamma_i} \boldsymbol{P_i} - \boldsymbol{\Gamma_d} \boldsymbol{d} \leq \boldsymbol{F}, \tag{10}$$

where (7) stands for the operation cost; (8) denotes the load balance constraints; (9) is the compact form of (4)-(6); (10) represent the transmission constraints. $\boldsymbol{P_i} \in \mathbb{R}^T$ is the output vector of unit i. Matrix $\boldsymbol{\Gamma_i} \in \mathbb{R}^{2N_l T \times T}$, and matrix $\boldsymbol{\Gamma_d} \in \mathbb{R}^{2N_l T \times N_b T}$.

Due to the forecasting errors of renewables and loads, ISOs/RTOs need to run SCED on a rolling basis in real time to balance the system. Recently, some approaches have been introduced to solve the SCUC/SCED problem considering uncertainties due to variations of load and renewables. Both stochastic SCUC/SCED and robust SCUC/SCED are studied intensively when considering uncertainties.

To our best knowledge, this paper is the first work on robust ramping products which can be immunized against any uncertainty. Hence, the following assumptions are made so that we can focus on the core concept.

- Transmission loss is ignored in the SCED problem.
- The proposed approach is for ex ante dispatch and ex ante pricing.
- Units bid only energy price. The reserve bid is zero.
- Uncertainty comes from loads. Renewables are treated as negative loads. Other uncertainties such as contingencies are not discussed in this paper.
- Uncertainty set information is available to the ISO/RTO.

B. Affinely Adjustable Robust SCED

The basic idea of AARO optimization can be traced back to [15], in which a linear "feedback" in control theory is used to adjust dispatch with the realization of load. Authors in [13], [14], [28] applied it to solve SCED problem. In the AARO SCED, the generation output is affinely adjusted according to the uncertainties,

$$\boldsymbol{\hat{P}_i} = \boldsymbol{P_i} + \boldsymbol{G_i}\boldsymbol{\epsilon}, \forall i, \tag{11}$$

where matrix $\boldsymbol{G_i} \in \mathbb{R}^{T \times N_b T}$ is the affine adjustment matrix. It should be noted that $\boldsymbol{G_i}$ is a decision variable in the proposed approach. $\boldsymbol{P_i} \in \mathbb{R}^T$ and $\boldsymbol{\hat{P}_i} \in \mathbb{R}^T$ are the base dispatch and adjusted dispatch, respectively. $\boldsymbol{\epsilon} \in \mathbb{R}^{N_b T}$ is the uncertainty vector (i.e., deviation of loads from forecasted values). $\boldsymbol{\epsilon}$ can be regarded as in-elastic loads that ISOs cannot control. The new unit dispatch can be regulated based on the load deviation. It is noted that $\boldsymbol{\epsilon} \in \mathcal{U}$, and

$$\mathcal{U} := \{\boldsymbol{\epsilon} : \boldsymbol{S}\boldsymbol{\epsilon} \leq \boldsymbol{h}\}, \tag{12}$$

where matrix $\boldsymbol{S} \in \mathbb{R}^{N_k \times N_b T}$ and vector $\boldsymbol{h} \in \mathbb{R}^{N_k}$. $\mathcal{U}$ is a polyhedron which is general enough to include more than just the lower and upper bounds for uncertainty. The entry in $\boldsymbol{h}$ is considered as uncertainty level which is positive. The AARO SCED, denoted as (ROP), can be formulated as

$$\text{(ROP)} : \min_{\boldsymbol{P_i}, \boldsymbol{G_i}} \sum_i C(\boldsymbol{P_i}) \tag{13}$$
$$\text{s.t.} \quad \sum_i \boldsymbol{\hat{P}_i} = \boldsymbol{D}\left[\boldsymbol{d} + \boldsymbol{\epsilon}\right], \forall \boldsymbol{\epsilon} \in \mathcal{U} \tag{14}$$
$$\boldsymbol{A}\boldsymbol{\hat{P}_i} \leq \boldsymbol{R_i}, \forall i, \forall \boldsymbol{\epsilon} \in \mathcal{U} \tag{15}$$
$$\sum_i \boldsymbol{\Gamma_i}\boldsymbol{\hat{P}_i} - \boldsymbol{\Gamma_d}\left[\boldsymbol{d} + \boldsymbol{\epsilon}\right] \leq \boldsymbol{F}, \forall \boldsymbol{\epsilon} \in \mathcal{U} \tag{16}$$
$$(11), \forall \boldsymbol{\epsilon} \in \mathcal{U}.$$

The problem (ROP) is converted to a computationally tractable problem (P) as follows, where the constraints including uncertain parameters are exactly reformulated.

$$(\text{P}):\min_{\boldsymbol{P_i},\boldsymbol{G_i},\boldsymbol{\rho_i},\boldsymbol{\zeta}}\ \sum_i C\left(\boldsymbol{P_i}\right) \tag{17}$$

$$\text{s.t.}\ (\boldsymbol{\lambda})\quad \sum_i \boldsymbol{P_i} = \boldsymbol{Dd} \tag{18}$$

$$(\boldsymbol{\gamma})\quad \sum_i \boldsymbol{G_i} = \boldsymbol{D} \tag{19}$$

$$(\boldsymbol{\alpha_i} \geq \boldsymbol{0})\quad -\boldsymbol{R_i} + \boldsymbol{AP_i} + \boldsymbol{\rho_i}^\top \boldsymbol{h} \leq \boldsymbol{0}, \forall i \tag{20}$$

$$(\boldsymbol{\beta_i})\quad \boldsymbol{AG_i} - \boldsymbol{\rho_i}^\top \boldsymbol{S} = \boldsymbol{0}, \forall i \tag{21}$$

$$(\boldsymbol{\eta} \geq \boldsymbol{0})\quad -\boldsymbol{F} - \boldsymbol{\Gamma_d d} + \sum_i \boldsymbol{\Gamma_i P_i} + \boldsymbol{\zeta}^\top \boldsymbol{h} \leq \boldsymbol{0} \tag{22}$$

$$(\boldsymbol{\tau})\quad \sum_i \boldsymbol{\Gamma_i G_i} - \boldsymbol{\Gamma_d} - \boldsymbol{\zeta}^\top \boldsymbol{S} = \boldsymbol{0} \tag{23}$$

$$(\boldsymbol{\xi}, \boldsymbol{\sigma})\quad \boldsymbol{\rho_i} \geq \boldsymbol{0}, \boldsymbol{\zeta} \geq \boldsymbol{0}, \tag{24}$$

where $\boldsymbol{\rho_i}^\top \in \mathbb{R}^{4T\times N_k}$ and $\boldsymbol{\zeta}^\top \in \mathbb{R}^{2N_l T\times N_k}$ are also variables. (18) and (19) are derived from (11), (14), and (8). (20)-(23) are obtained from strong duality. Problem (P) is *convex* and can be solved efficiently using commercial solvers such as CPLEX and GUROBI. It can be observed that no PDF information is required to solve (P).

Different from the standard SCED (7)-(10), extra terms $\boldsymbol{\rho_i}^\top \boldsymbol{h}$ and $\boldsymbol{\zeta}^\top \boldsymbol{h}$ are added in inequality constraints (20) and (22), respectively, in problem (P). As $\boldsymbol{\rho_i}^\top \geq \boldsymbol{0}, \boldsymbol{\zeta}^\top \geq \boldsymbol{0}$ and $\boldsymbol{h} \geq \boldsymbol{0}$, $\boldsymbol{\rho_i}^\top \boldsymbol{h}$ and $\boldsymbol{\zeta}^\top \boldsymbol{h}$ are non-negative. It indicates that certain unit and transmission constraints in standard SCED are replaced with stronger constraints in the robust framework. Thus, the system actually keeps certain flexibilities for uncertainty accommodation. These flexibilities are also called reserves. There are four salient features in this model.

- First, the reserves are fully deliverable, which means the useful reserves can also be delivered to the desired buses. In contrast, transmission line congestions are not considered in the existing FRP model.
- Second, the reserves are immunized against any uncertainty in the following intervals. The existing FRPs are just modeled based on the ramping requirements at each time interval independently, but the transition from $\hat{P}_{i,t}$ to $\hat{P}_{i,t+1}$ is ignored.
- Third, the polyhedron in equation (12) can reduce the conservativeness.
- Fourth, the ramping requirements are determined automatically.

III. Deliverable Robust Ramping Products

An Uncertainty Mitigator (UM) refers to a flexible resource provider that participates in the management of uncertainties. The flexible resources include generators with available ramping capabilities and adjustable loads. UMs have to keep certain reserves in order to accommodate the uncertainties. Compared to (9), constraint (20) may be binding even when the scheduled dispatch does not reach the capacity limits (6) or ramping limits (4)-(5). Based on the optimal solution to (P), the DRRP can be calculated. We use subscript * to denote the optimal solution to (P) in this paper.

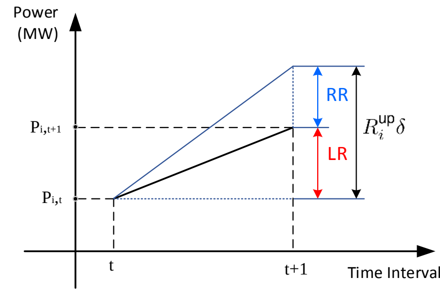

Fig. 1. Illustration of Upward Ramping Reserve (LR: Locked Ramping, RR: Ramping Reserve, R_i^{up}: Upward Ramping Rate Limit, δ: Timespan)

A. Definitions of Deliverable Robust Ramping Products

The generation ramping reserve is defined as the unused ramping capability of a generator in a given timespan δ. In order to get the ramping reserve, we first define the locked ramping capability as

$$Q_{i,t}^{\text{r,l}} \triangleq P_{i,t+1}^* - P_{i,t}^*, \forall i, t, \tag{25}$$

which is the scheduled ramping capability in the given timespan δ (i.e., from t to t+1), hence cannot be used for uncertainty accommodation. Then, the generation ramping reserve in the given timespan δ can be formulated as

$$Q_{i,t}^{\text{r,u}} \triangleq R_i^{\text{up}}\delta - Q_{i,t}^{\text{r,l}}, \forall i, t, \tag{26}$$

$$Q_{i,t}^{\text{r,d}} \triangleq R_i^{\text{down}}\delta + Q_{i,t}^{\text{r,l}}, \forall i, t, \tag{27}$$

where $Q_{i,t}^{\text{r,u}}$ and $Q_{i,t}^{\text{r,d}}$ are the upward and downward generation ramping reserves, respectively. The concept of the upward ramping reserve is illustrated in Fig. 1. The ramping reserve is the available ramping rate less the locked ramping. The ramping reserve guarantees that the uncertainty mitigator still has additional ramping capability during the scheduled ramping process. In the existing AS market, the “locked” ramping is normally ignored for the spinning reserves [29], [30]. In the RTM, the time resolution is generally 5 or 15 minutes. So, if we ignore the ramping process, there is a chance that the system cannot provide enough ramping capability to accommodate the uncertainties. In contrast, the time resolution is one hour in DAM, and the units have enough time to redispatch even if the locked ramping is ignored [19], [29].

The generation capacity reserve is defined as the unused generation capacity of a generator, i.e.,

$$Q_{i,t}^{\text{c,u}} \triangleq P_i^{\max} - P_{i,t}^*, \forall i, t, \tag{28}$$

$$Q_{i,t}^{\text{c,d}} \triangleq P_{i,t}^* - P_i^{\min}, \forall i, t, \tag{29}$$

where $Q_{i,t}^{\text{c,u}}$ and $Q_{i,t}^{\text{c,d}}$ are the upward and downward generation capacity reserves, respectively. From the system's point of view, the total capacity reserves are fixed when the unit commitment and load level are determined.

The flexibility UM can provide is subject to both the ramping rate limit and the capacity limit. They contribute to the uncertainty management and load following in the AARO SCED approach. They can be delivered to the desired location while respecting network constraints (i.e., deliverability) and can be immunized against all predefined uncertainties (i.e., robustness). Due to the deliverability and robustness of these reserves, they are called **Deliverable Robust Ramping Products**.

B. Marginal Prices of DRRP

In most generation and reserve co-optimization approaches in AS market, the explicit reserve requirement constraint is modeled [19], [20], [31]. The shadow prices of this type of constraint is employed to derive the reserve price which reflects the coupled effects of the generation and reserve. Instead of setting the reserve manually and heuristically based on Monte Carlo simulations, the reserves in the AARO SCED are determined automatically in one shot. Although it has obvious advantages over the traditional reserve determination, it also poses new challenges on reserve price derivation. The existing pricing approaches cannot be used directly [19], [20] due to the lack of explicit reserve requirement constraints.

While the amount of reserves can be calculated according to (26)-(29), the question is how to set the prices for them. On the one hand, it is well known that not all the reserves are deliverable for uncertainty accommodation due to network constraints. On the other hand, the generation and reserve are coupled together in the RTM even if the reserve bid price is zero [32], and the market clearing price for reserve has certain relations with that for energy. In this paper, we call the reserve in (26)-(29) ***available reserve***. If a small increment of the reserve amount causes change of the operation cost in (P), then this type of reserve is called ***valuable reserve***. To determine the exact value of a reserve, we derive the marginal prices for the reserve according to the Lagrangian function in Appendix A.

The ramping reserve price for UM i is defined as the marginal cost due to a unit decrement of the generation ramping rate of UM i. The capacity reserve price for UM i is defined as the marginal cost due to a unit decrement of the generation capacity of UM i. These prices can be explained as the opportunity cost. They can be obtained from the Lagrangian function at the optimal point as

$$\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r}} \triangleq -\frac{\partial \boldsymbol{\mathcal{L}}^*}{\partial \boldsymbol{R}_{\boldsymbol{i}}} = \boldsymbol{\alpha}_{\boldsymbol{i}}^*, \tag{30}$$

where $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r}} \in \mathbb{R}^{4T}$. Note that $\boldsymbol{\alpha}_{\boldsymbol{i}}^*$ consists of Lagrangian multipliers for unit ramping limits and unit capacity limits. Denote the prices for upward and downward ramping reserves as $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r,ru}}$ and $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r,rd}}$, respectively. Denote the prices for upward and downward capacity reserves as $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r,cu}}$ and $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r,cd}}$, respectively. We have

$$\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r}} = \begin{bmatrix} \boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r,ru}} \\ \boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r,rd}} \\ \boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r,cu}} \\ \boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r,cd}} \end{bmatrix}.$$

The reserve provided by i is valuable if and only if $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r}}$ is non-zero.

The LMP for AARO SCED can be obtained based on its definition. It is the marginal cost due to a unit increment of the load. For unit i, it is formulated as

$$\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{e}} \triangleq \boldsymbol{\lambda}^* - \boldsymbol{\Gamma}_{\boldsymbol{i}}^{\top} \boldsymbol{\eta}^*, \tag{31}$$

where $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{e}} \in \mathbb{R}^{T}$. $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{e}}$ also consists of energy component and congestion component.

C. Credits to DRRP

Within the AARO framework, UMs help the system withstand the "load deviation" in the future. As the generation and the reserve are coupled together, the credit for reserve should reflect the coupling effect. The opportunity cost of providing the reserve exists in the AARO framework. In general, it is also the reserve credit entitled to the reserve provider in the electricity market. The total reserve credit to UM i (or opportunity cost) is

$$\Theta_i = \left(\boldsymbol{R}_{\boldsymbol{i}} - \boldsymbol{A}\boldsymbol{P}_{\boldsymbol{i}}^*\right)^{\top} \boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r}}, \tag{32}$$

which is the product of the reserve price and the reserve amount. In fact, the reserve price $\boldsymbol{\pi}_{\boldsymbol{i}}^{\mathrm{r}}$ reflects how much "value" the reserve has. $\boldsymbol{R}_{\boldsymbol{i}} - \boldsymbol{A}\boldsymbol{P}_{\boldsymbol{i}}^*$ reflects the available reserve, which is the reserve quantity at each time interval. Specifically, the total reserve credit entitled to i at t is

$$\theta_{i,t} = \pi_{i,t}^{\mathrm{r,ru}} Q_{i,t}^{\mathrm{r,u}} + \pi_{i,t}^{\mathrm{r,rd}} Q_{i,t}^{\mathrm{r,d}} + \pi_{i,t}^{\mathrm{r,cu}} Q_{i,t}^{\mathrm{c,u}} + \pi_{i,t}^{\mathrm{r,cd}} Q_{i,t}^{\mathrm{c,d}}. \tag{33}$$

Only when the reserve is a valuable reserve (i.e. $\pi_{i,t}^{\mathrm{r,ru}} + \pi_{i,t}^{\mathrm{r,cu}} \neq 0$ or $\pi_{i,t}^{\mathrm{r,rd}} + \pi_{i,t}^{\mathrm{r,cd}} \neq 0$) can UM i get the reserve credit. Otherwise, the reserve credit to UM i is zero even if the available reserve it provides is non-zero. There are similar phenomena in the traditional zonal-based reserve market. For example, the reserve price \$0/MWh at a specific zone occurs when the cleared system reserve is higher than the required amount in Case I of Section VI [19].

The proposed approach is for ex ante dispatch and ex ante pricing. With the uncertainty realization, the generators are supposed to be re-dispatched according the adjustment matrix $\boldsymbol{G}_{\boldsymbol{i}}$. At the end of the last interval, all real energy produced by generators are available. The deviations can be calculated and settled based on the ex ante prices.

IV. TIME-DECOUPLED DRRP

The approach proposed above can be implemented in the market to settle all time intervals, which is a simple process. In the real-time market, the ISO may prefer to clear the market and settle the first time interval only [22]. In this section, we propose a general approach for the settlement of the first interval based on a time-decoupled DRRP model. The existing FRP model, which also settles the first interval, is presented for comparison.

A. The Exiting FRP Model

The general idea of the FRP model in [23] is to model the future load ramping and uncertainties at the current interval. The ISOs try to make the prices reflect the energy cost and opportunity cost at each interval only. Without regulation, spinning, and non-spinning reserves, a simple illustrative model for the FRP can be formulated as

$$\min_{P_{i,t},Q_{i,t}^{\text{FRP,up}},Q_{i,t}^{\text{FRP,down}},\forall i,t} \quad \sum_{i,t} C(P_{i,t})$$

$$\text{s.t.} \quad (2)-(5) \tag{34}$$

$$P_i^{\min} \le P_{i,t} + Q_{i,t}^{\text{FRP,up}} \le P_i^{\max}, \forall i,t \tag{35}$$

$$P_i^{\min} \le P_{i,t} - Q_{i,t}^{\text{FRP,down}} \le P_i^{\max}, \forall i,t \tag{36}$$

$$0 \le Q_{i,t}^{\text{FRP,up}} \le R_i^{\text{up}}\delta, \forall i,t \tag{37}$$

$$0 \le Q_{i,t}^{\text{FRP,down}} \le R_i^{\text{down}}\delta, \forall i,t \tag{38}$$

$$\sum_i Q_{i,t}^{\text{FRP,up}} \ge Q_{\text{Req},t}^{\text{FRP,up}}, \forall t \tag{39}$$

$$\sum_i Q_{i,t}^{\text{FRP,down}} \ge Q_{\text{Req},t}^{\text{FRP,down}}, \forall t \tag{40}$$

where $Q_{\text{Req},t}^{\text{FRP,up}}$ and $Q_{\text{Req},t}^{\text{FRP,down}}$ are the ramping requirements at t determined by the ISOs. Historical data for the load ramping and uncertainty can be used in ramping requirement determination. It can be observed that the transmission constraints for $Q_{i,t}^{\text{FRP,up}}$ and $Q_{i,t}^{\text{FRP,down}}$ are not enforced. It should be noted that the price of the existing ramping product can also be interpreted as having two components according to the optimality conditions. For example, the price of the upward ramping product, which is the shadow price of (39), is composed of a capacity component from (35) and a ramping component from (37).

B. Time-decoupled DRRP

The proposed DRRP can be immunized against any uncertainty. The ramping requirements are determined automatically in the problem (P), instead of using the heuristic methods. However, the challenge to settle the first interval is that the model is time-coupled. The unit increment of the load at the first interval may impact the cost in other intervals, and the LMPs at different intervals are coupled together due to the ramping constraints. At the same time, the reserves withheld at the first interval may be used for the following intervals. To get the price signals for the first interval, the following principles are followed.

1) The ISO desires to make the best decision (i.e. the minimum cost at interval 1 and the minimum total cost in all intervals) based on currently available information.
2) The reserves (i.e., flexibilities) withheld at interval 1 can be immunized against any uncertainty in the following intervals. The reserves are deliverable. A generator can adjust from $\hat{P}_{i,t}$ to $\hat{P}_{i,t+1}$ after uncertainty accommodation.
3) LMP is defined as the additional cost at interval 1 due to the unit increment of the load at interval 1 while the load ramping and uncertainties in the other intervals remain the same.
4) Ramping and capacity reserve prices are the opportunity costs at interval 1 only. As only the first interval is settled, the reserve provider only gets compensation for the first interval.

To settle the first interval, we should solve another problem after solving problem (P). The problem is formulated as

$$(\text{PM}): \min_{\boldsymbol{P_i},\boldsymbol{G_i},\boldsymbol{\rho_i},\boldsymbol{\zeta}} \sum_i C(P_{i,1})$$

$$\text{s.t.} \quad (18)-(24)$$

$$(\tilde{\mu} \ge 0) \quad \sum_i C(\boldsymbol{P_i}) \le Z^* \tag{41}$$

where Z^* is the optimal value to problem (P). The objective function of (PM) is the operation cost of the first interval only. Constraint (41) ensures the optimality of the cost of all intervals. Warm-start techniques of solvers can be used here.

With the definitions of LMP in principle 3) and reserve prices in principle 4), the new LMP and reserve price at the first interval are

$$\begin{cases} \hat{\pi}_{i,1}^{\text{e}} = \mathbf{1}^\top \tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{e}} - \tilde{\mu}\cdot \mathbf{1}^\top \boldsymbol{\pi}_{\boldsymbol{i}}^{\text{e}}, \forall i, & (42) \\ \hat{\pi}_{i,1}^{\text{r,ru}} = \mathbf{1}^\top \tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{r,ru}} - \tilde{\mu}\cdot \mathbf{1}^\top \boldsymbol{\pi}_{\boldsymbol{i}}^{\text{r,ru}}, \forall i, & (43) \\ \hat{\pi}_{i,1}^{\text{r,rd}} = \mathbf{1}^\top \tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{r,rd}} - \tilde{\mu}\cdot \mathbf{1}^\top \boldsymbol{\pi}_{\boldsymbol{i}}^{\text{r,rd}}, \forall i, & (44) \\ \hat{\pi}_{i,1}^{\text{r,cu}} = \mathbf{1}^\top \tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{r,cu}} - \tilde{\mu}\cdot \mathbf{1}^\top \boldsymbol{\pi}_{\boldsymbol{i}}^{\text{r,cu}}, \forall i, & (45) \\ \hat{\pi}_{i,1}^{\text{r,cd}} = \mathbf{1}^\top \tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{r,cd}} - \tilde{\mu}\cdot \mathbf{1}^\top \boldsymbol{\pi}_{\boldsymbol{i}}^{\text{r,cd}}, \forall i, & (46) \end{cases}$$

where $\mathbf{1} \in \mathbb{R}^T$ is a vector with all elements being 1; $\tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{e}}$, $\tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{r,cu}}$, $\tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{r,cd}}$, $\tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{r,ru}}$, and $\tilde{\boldsymbol{\pi}}_{\boldsymbol{i}}^{\text{r,rd}}$ are intermediate prices calculated based on the dual variables in (PM); $\boldsymbol{\pi}_{\boldsymbol{i}}^{\text{e}}$, $\boldsymbol{\pi}_{\boldsymbol{i}}^{\text{r,cu}}$, $\boldsymbol{\pi}_{\boldsymbol{i}}^{\text{r,cd}}$, $\boldsymbol{\pi}_{\boldsymbol{i}}^{\text{r,ru}}$, and $\boldsymbol{\pi}_{\boldsymbol{i}}^{\text{r,rd}}$ are the prices calculated according to (30) based on the dual variables in (P), respectively. Refer to Appendix-C for the derivation.

In (42)-(46), all the prices are composed of two terms. The first term is the summation of the prices calculated based on (PM). It reflects the impact of the optimality of dispatches in the first interval on the time-decoupled price. The second term is the summation of the prices in (P) multiplied by $\tilde{\mu}$. It reflects the impact of the optimality of dispatches in all intervals on the time-decoupled price. The summations in both terms reflect the impact of ramping constraints, which couple the prices at different intervals together. (43)-(46) reflect the opportunity cost of unit i keeping its generation level at $P_{i,1}^*$, because $P_{i,1}^*$ may not be optimal from the first interval's point of view, although it is optimal from all intervals' point of view.

As only the first interval is settled, there is no locked ramping, i.e.,

$$Q_{i,t}^{\text{r,l}} = 0.$$

Therefore, the ramping reserves are changed to

$$\hat{Q}_{i,1}^{\text{r,u}} = R_{i,t}^{\text{up}}\delta, \quad \hat{Q}_{i,1}^{\text{r,d}} = R_{i,t}^{\text{down}}\delta.$$

The capacity reserves remain the same.

V. Case Study

A 3-Bus system and the modified IEEE 118-bus system are studied in this section to illustrate the concepts of available/valuable ramping/capacity reserves and the associated prices, as well as their impacts on market participants. The simulations are carried out using CPLEX 12.5 on PC with Intel i7-3770 3.40GHZ 8GB RAM.

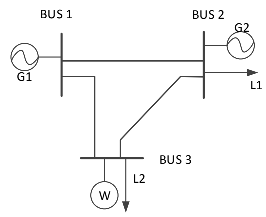

Fig. 2. One-line Diagram for 3-Bus System

TABLE I
LINE DATA FOR THE 3-BUS SYSTEM

Line	From	To	Reactance (p.u.)	Flow Limit (MW)
1	1	2	0.1	82
2	1	3	0.15	100
3	2	3	0.1	50

A. 3-Bus System

The one-line diagram for the 3-Bus system is presented in Fig. 2. There are two units and one wind farm in the system. The generation output from the wind farm is modeled as negative load. All loads are aggregated net load in L1 and L2. The transmission line and unit parameters are presented in Table I and Table II, respectively. For simplicity, three time intervals are studied and a single-segment incremental cost (IC) is employed to represent the fuel cost. The time resolution is 15 minutes. It is assumed that both units in the system are committed, which is determined in the DAM. Load at the current interval (i.e., t=1) is assumed to be accurate. Loads at t=2 and t=3 are forecasted based on current available information, and forecasting errors may exist. Assume that the expectation of uncertainties at t=2 and t=3 are 0, and their probability distribution is unknown. Ex ante dispatch and pricing are studied in this section. Three cases are simulated based on the data provided above.

- Case 1: Transmission flow limits are enforced. Two settlement options, i.e. settling all intervals and settling the first interval only, are illustrated.
- Case 2: Transmission flow limits are enforced. The drawbacks of the existing FRP model are analyzed.
- Case 3: Transmission flow limits are not enforced. It is equivalent to having all the loads and generators at one bus. The comparisons are presented for the existing FRP model and the proposed DRRP model.

TABLE II
UNIT DATA FOR THE 3-BUS SYSTEM

Unit #	Bus #	IC ($/MWh)	$P^{\max *}$	$P^{\min *}$	$R^{\text{up}**}$	$R^{\text{down}**}$	$P_0{}^*$
1	1	10	180	0	25	25	120
2	2	25	80	0	10	10	10

* MW ** MWh/15min

TABLE III
LOAD DATA FOR THE 3-BUS SYSTEM (MW)

t	Bus #	Forecasted	LB	UB	Actual
1	2	80	80	80	80
	3	60	60	60	60
2	2	90	82.5	97.5	97.5
	3	65	62	68	68
3	2	95	87	103	95
	3	72	69	75	73

TABLE IV
GENERATION AND UPWARD RESERVES IN THE DRRP MODEL WITH TRANSMISSION CONSTRAINTS

t	Generation[a]		Cap. Reserve[a]		Ramp. Reserve[b]	
	G1	G2	G1	G2	G1	G2
1	126.5	13.5	53.5	66.5	19.85	0.15
2	131.65	23.35	48.35	56.65	13.05	9.95
3	143.6	23.4	36.4	56.6	25	10
1	126.5	13.5	53.5	66.5	25	10

[a] MW; [b] MWh/15min

TABLE V
LMP AND UPWARD RESERVE PRICES IN THE DRRP MODEL WITH TRANSMISSION CONSTRAINTS

t	LMP[a]			Cap. Res. Price[a]		Ramp. Res. Price[c]	
	Bus1	Bus2	Bus3	G1	G2	G1	G2
1	10	10	10	0	0	0	15
2	10	32.5	23.5	0	0	0	7.5
3	10	32.5	23.5	0	0	0	0
1	10	25	19	0	0	0	15

[a] $/MWh; [b] $/(MWh/15min)

1) Case 1: There are two options for the ISO to settle the market with the proposed DRRP model. One is to settle all the intervals according to the solutions to (P), and the other is to only settle the first interval according to the solutions to (PM). The dispatch/reserve and prices obtained from the DRRP model are shown in Table IV and Table V, respectively. The first three rows in the two tables show the solutions to problem (P), and the last row highlighted in pink lists the solutions to problem (PM).

We first analyze the scenario of settling all intervals. We just need to solve problem (P) for all time intervals (t=1, t=2, t=3) once at the beginning of t=1. With the adjustment matrices, any load deviation can be followed by re-dispatching G1 and G2. The adjustment matrix of G1 is

$$\boldsymbol{G_1} = \begin{bmatrix} 1 & 1 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0.98 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0.4 \end{bmatrix},$$

and the adjustment matrix of G2 is

$$\boldsymbol{G_2} = \begin{bmatrix} 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0.02 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & 0.6 \end{bmatrix}.$$

For example, if the loads at Bus 1 and Bus 3 at t=2 are increased to 97MW and 67.5MW, respectively, then the units can be re-dispatched based on the adjustment matrices to $131.65 + 0.98 \cdot 7 + 1 \cdot 2.5 = 141.01$MW and $23.35 + 0.02 \cdot 7 + 0 \cdot 2.5 = 23.49$MW. In this case, the settlement on energy should also be adjusted based on these deviations.

It is observed that the capacity reserves are not scarce resources, i.e. the on-line capacity is adequate. According to

TABLE VI
CREDITS ENTITLED TO GENERATORS BASED ON RESERVE PRICES WHEN ALL INTERVALS ARE SETTLED IN THE BASE CASE ($)

t	G1	G2
1-2	0	$15 \cdot 0.15 \cdot 0.25 = 0.5625$
2-3	0	$7.5 \cdot 9.95 \cdot 0.25 = 18.6563$

the definition in this paper, they are just available reserves but not valuable reserves. In contrast, the prices of upward ramping reserve at t=1 and t=2 are non-zeros. According to the definition in this paper, they are valuable reserves. Table VI shows the reserves credits in the base case. Uncertainty mitigator G2 is entitled to \$0.56 for the ramping reserves between t=1 and t=2, and is entitled to \$18.66 for the ramping reserves between t=2 and t=3. The credit is calculated based on (32). It is noted that the credits are time-coupled, as the ramping reserve is calculated according to the difference of the power outputs between two intervals.

The LMP is \$10/MWh at t=1 for Bus 2 where G2 is located. It seems that G2, which has an IC of \$25/MWh, cannot recover its bid-based cost. However, as we settle all the intervals, G2's bid-based cost can be recovered from t=2 and t=3. For example, in the base case, G2's profit is

$$\Big(13.5 \cdot (10 - 25) + 23.35 \cdot (32.5 - 25) \\ +23.4 \cdot (32.5 - 25)\Big) \cdot 0.25 + 0.5625 \\ +18.7563 = \$56.35.$$

Compared to the existing FRP model, which only utilizes prices at t=1, the proposed DRRP model utilizes prices at t=1, t=2, and t=3, which are actually coupled together. By settling all intervals, we can take those coupling effects into consideration.

Next, we analyze the scenario of settling the first interval only. Although it is easy to settle all intervals based on the solution to (P) in terms of implementation, some may argue that setting first interval only is economically more efficient as more information will be available later. The proposed time-decoupled DRRP model in Section IV provides the option to settle the first interval only.

In this scenario, the dispatch instructions at the first interval by solving problem (PM) are the same as those by solving problem (P). However, the reserves and prices are different. It can be observed that the amount of ramping reserve for G2 is increased from 0.15MWh/15min to 10MWh/15min. The LMP at Bus 2 increases to \$25/MWh from \$10/MWh, and the LMP at Bus 3 increases to \$19/MWh. The LMP at Bus 2 is equal to G2's bid-based cost. So, G2 can recover its bid-based cost in this scenario. Its profit is

$$\Big(13.5 \cdot (25 - 25) + 10 \cdot 15\Big) \cdot 0.25 = \$37.5. \tag{47}$$

2) Case 2: The existing FRP model does not consider the congestions caused by delivering the ramping capability, although the transmission constraints are enforced for the dispatch. Consistent with the practice in the real-time market, we solve the FRP model at the beginning of each interval and

TABLE VII
GENERATION AND FRP IN THE FRP MODEL WITH TRANSMISSION CONSTRAINTS

	t	Generation [a]		Upward FRP [b]		Downward FRP [b]	
		G1	G2	G1	G2	G1	G2
At t=1	1	135.8	4.2	25	0.5	0	0
	2	140.8	14.2	13	10	0	0
	3	143.6	23.4	0	0	0	0
At t=2	2	142	14.2	12.5	0	25	0
	3	143.6	23.4	0	0	0	0

[a] MW; [b] MWh/15min.

TABLE VIII
LMP AND FRP PRICES IN THE FRP MODEL WITH TRANSMISSION CONSTRAINTS

	t	LMP[a]			Price of FRP[b]	
		Bus 1	Bus 2	Bus 3	Upward	Downward
At t=1	1	10	10	10	0	0
	2	10	40	28	0	0
	3	10	25	19	0	0
At t=2	2	10	500	304	0	0
	3	10	25	19	0	0

[a] \$/MWh; [b] \$/(MWh/15min)

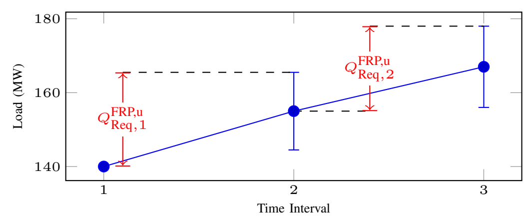

Fig. 3. System-wide Load and Ramping Requirement for the FRP Model in the 3-Bus System

only settle the first interval. The upward ramping requirement for (39) at interval t is determined as

$$\max\Big\{0, \sum_m d_{m,t+1} - \sum_m d_{m,t} + \max_{\epsilon\in\mathcal{U}} \sum_m \epsilon_{m,t+1}\Big\}, \tag{48}$$

and the downward ramping requirement for (40) at interval t is determined as

$$\max\Big\{0, \sum_m d_{m,t} - \sum_m d_{m,t+1} - \min_{\epsilon\in\mathcal{U}} \sum_m \epsilon_{m,t+1}\Big\}. \tag{49}$$

In this example, the upward ramping requirements at t=1 and t=2 are 25.5MWh/15min and 23MWh/15min, respectively, and the downward ramping requirements at both t=1 and t=2 are 0MWh/15min. They are illustrated in Fig. 3. The penalty for the load curtailment is assumed to be \$500/MWh. Simulation results in Table VII and Table VIII reveal two drawbacks of the existing FRP model compared to the proposed DRRP model.

First, some generators may not recover their bid-based cost. At t=1, the FRP prices are \$0/MWh for the first interval. The first row of Table VIII shows that the system-wide LMP is \$10/MWh. With the bid-based cost of \$25/MWh, G2's profit is

$$\Big(4.2 \cdot (10 - 25) + 0.5 \cdot 0\Big) \cdot 0.25 = -\$15.75,$$

TABLE IX
GENERATION AND FRP IN THE FRP MODEL WITHOUT ENFORCING TRANSMISSION CONSTRAINT

Scenario	Generation[a]		Upward FRP[b]		Downward FRP[b]	
	G1	G2	G1	G2	G1	G2
1	140	0	25	0.5	0	0
2	134.5	5.5	15.5	10	0	0

[a] MW; [b] MWh/15min

TABLE X
PRICES IN THE FRP MODEL WITHOUT ENFORCING TRANSMISSION CONSTRAINT

Scenario	LMP($/MWh)			Price of FRP ($/(MWh/15min))	
	Bus 1	Bus 2	Bus 3	Upward	Downward
1	10	10	10	0	0
2	25	25	25	15	0

which is negative. In contrast, G2 can get positive profit in the proposed method as shown in (47). It indicates that the ISO has to make a whole on the bid cost recovery for G2 with the existing FRP model. The fundamental reason of the revenue inadequacy is that the ramping constraint for G2 between t=1 and t=2 is binding with a shadow price of $15/(MWh/15min). It means that LMPs at t=1 and t=2 are still coupled together. LMP at t=1 is 25-15=$10/(MWh/15min) and LMP at t=2 is 25+15=$40/(MWh/15min) as the unit increment of load at t=1 reduces the ramping between t=1 and t=2 while that at t=2 increases the ramping between t=1 and t=2.

Second, load curtailment may occur in future time intervals. In this example, load curtailment occurs at t=2 due to the congestion on Line 1-2 that limits the delivery of the ramping capability. The fourth row of Table VIII shows that the LMP at Bus 2 is $500/MWh, which is the penalty price for the load curtailment at Bus 2 (9.3MW). The cause of the load curtailment is that the dispatch at t=1 is prescribed without considering the delivery of the ramping capability, although the system-wide ramping requirement is satisfied.

These observations demonstrate that the existing FRP model cannot fully address the issues of ramping deficiency and uncertainty management. Furthermore, the recovery of bid-based cost, which is another goal of FRP, may not be achieved if there is line congestion.

3) Case 3: When transmission flow limits are ignored or not enforced, the uncertainty and ramping problem is much simpler. As this model is very simple, we only run the existing FRP model and the proposed DRRP model once at the beginning of t=1 and settle the first interval only.

The simulation results for the existing FRP model are shown in Table IX and Table X. In the base Scenario 1, all the loads are supplied by G1, which has lower bid cost. The LMPs at all buses are $10/MWh while the FRP prices are all 0. Thus, G1 and G2 get zero credits for the non-zero upward FRP they provide. According to the results in Table XI and Table XII, the proposed DRRP model has the same solution in this scenario.

In Scenario 2, two changes are considered: $P_1^{\max}$ is reduced from 180MW to 150MW and $d_{2,3}$ is reduced from 95MW

TABLE XI
GENERATION AND UPWARD RESERVES IN THE DRRP MODEL WITHOUT ENFORCING TRANSMISSION CONSTRAINT

Scenario	Generation[a]		Cap. Reserve[a]		Ramp. Reserve[b]	
	G1	G2	G1	G2	G1	G2
1	140	0	25	10	25	10
2	134.5	5.5	15.5	74.5	25	10

[a] MW; [b] MWh/15min

TABLE XII
PRICES IN THE DRRP MODEL WITHOUT ENFORCING TRANSMISSION CONSTRAINT

Scenario	LMP($/MWh)			Cap. Res. Price[a]		Ramp. Res. Price[b]	
	Bus1	Bus2	Bus3	G1	G2	G1	G2
1	10	10	10	0	0	0	0
2	25	25	25	15	0	0	15

[a] $/MWh; [b] $/(MWh/15min)

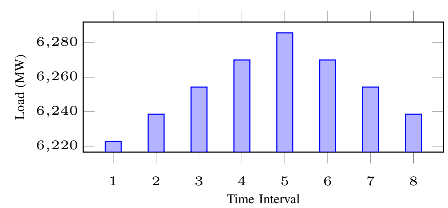

Fig. 4. System-wide Net Load

to 85MW. The load supplied by G2 increases to 5.5MW from 0MW in the existing FRP model according to Table IX. The upward FRPs are 15.5MWh/15min and 10MWh/15min, respectively, according to Table IX. The LMP increases to $25/MWh according to Table X. As the price of upward FRP increases to $15/(MWh/15min), G1 and G2 can get FRP credits

$$15 \cdot 15.5 \cdot 0.25 = \$58.125, \quad \text{and} \quad 10 \cdot 15 \cdot 0.25 = \$37.5,$$

respectively. It can be observed that the dispatches and LMPs are the same in the proposed DRRP model according to Table XI and Table XII. However, G1 gets the capacity reserve credit

$$15 \cdot 15.5 \cdot 0.25 = \$58.125.$$

G2 gets the ramping reserve credit

$$10 \cdot 15 \cdot 0.25 = \$37.5.$$

In this scenario, although the types of credits are different in the two models, the amounts of total reserve credits are the same for both generators. It should be emphasized that this is not a general conclusion, as we also ensure the robustness and adopt the affine policy in the DRRP.

B. Modified IEEE 118-Bus System

There are 54 traditional units and 186 branches in the modified IEEE 118-Bus system. The scheduling period is 2 hours, and the time interval is 15 minutes. The loads are depicted in Fig. 4. The UCs are determined in advance by

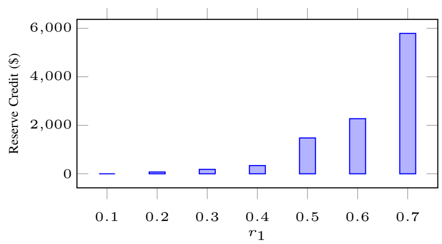

Fig. 5. Total Reserve Credit with Respect to Uncertainty Levels and Fixed Nominal Wind Power ($r_2 = 1$)

the solution to robust SCUC problem with 5% reserves. Five wind farms are introduced in the system, and they are located at buses 11, 49, 60, 78, and 90, respectively. We denote the set of buses with uncertainty as $\mathcal{M}$. It is assumed that the forecasted power output (i.e. nominal output) and installed capacity for each wind farm are 100 MW and 200 MW, respectively. The uncertainties in this case are from the RES only. The uncertainty $\epsilon_{m,t}$ satisfies

$$\begin{cases} |\epsilon_{m,t}| \leq 100 \cdot r_1 \cdot \Big(1 + 0.01 \cdot (t-1)\Big), m \in \mathcal{M}, \forall t \\ \Big| \sum_m \epsilon_{m,t} \Big| \leq 500 \cdot r_1 \cdot r_2 \cdot \Big(1 + 0.01 \cdot (t-1)\Big), \forall t \end{cases}$$

where r_1 reflects the forecast error confidence interval for a single wind farm [4], [14], and r_2 reflects the forecast error confidence interval for the aggregated wind output. When $r_2 < 1$, it indicates that the aggregated forecast error confidence interval is smaller than the sum of five error confidence intervals. In the experiment, the forecast error increases with the time intervals. The detailed data including unit parameters, line reactance and ratings, and net load profiles can be found at http://motor.ece.iit.edu/Data/118_UMP.xls.

We consider the interval bounds for the uncertainties, and perform the sensitivity analysis with respect to r_1. Fig. 5 shows the total reserve credits (RC) including ramping reserve credits and capacity reserve credits that the UMs receive with the change of r_1. When r_1 is high, the UMs are also entitled to high credits. As shown in (32), the reserve credits are the sum of the products of the amount of valuable reserve and the price of the valuable reserve. They are analyzed as follows.

Table XIII presents the upward/downward available reserves and valuable reserves at t=2 with increasing forecast errors, fixed normal wind power output (100MW each), and fixed r_2. The $r_1 \in [0.1, 0.7]$, so the error in percentage of the installed capacity (200MW each) is from 5% to 35%. It is observed that the available reserves remain the same while valuable reserve change dramatically with the forecast errors. As shown in Table XIII, upward available ramping reserve remains 886.70MWh/15min, and the capacity reserve remains 661.43MW. The main reason is that the unit commitment and load demand is fixed at t=2 in the system. In contrast, the upward valuable reserve is 0 when $r_1 = 0.1$. It indicates that the opportunity cost of keeping the ramping reserve for UM is zero as it can recover the profit from the energy credit. When r_1 is 0.2, 0.3 and 0.4, the valuable ramping reserve is around 180MWh/15min, and the valuable capacity reserve is around 11MW, 61MW, and 112MW, respectively. UMs are entitled to credits by keeping the reserves, which is also shown in Fig. 5.

TABLE XIII
RESERVES WITH RESPECT TO INCREASING UNCERTAINTY LEVELS AND FIXED NOMINAL WIND POWER ($r_2 = 1, t = 2$)

r_1	Upward Reserve				Downward Reserve			
	AvaRamp	ValRamp	AvaCap	ValCap	AvaRamp	ValRamp	AvaCap	ValCap
0.1	886.79	0	661.43	0	938.46	0	4203.57	0
0.2	886.79	180.79	661.43	10.61	938.46	10.37	4203.57	0
0.3	886.79	180.29	661.43	61.36	938.46	0	4203.57	0
0.4	886.79	179.79	661.43	112.11	938.46	0	4203.57	0
0.5	886.79	479.29	661.43	162.86	938.46	361.61	4203.57	0
0.6	886.79	513.33	661.43	215.49	938.46	337.5	4203.57	4.52
0.7	886.79	684.04	661.43	316.72	938.46	680.33	4203.57	12.14

AvaRamp: Available Ramping Reserve (MWh/15min); ValRamp: Valuable Ramping Reserve (MWh/15min); AvaCap: Available Capacity Reserve (MW); ValCap: Valuable Capacity Reserve (MW);

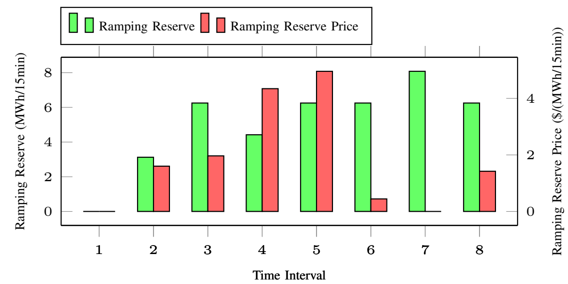

Fig. 6. Upward Ramping Reserve and Price for Unit 42 ($r_1 = 0.7, r_2 = 1$)

It suggests that the opportunity cost of keeping the reserve is non-zero, i.e., UMs can get more profits by deviating from the dispatch instruction if they are not entitled to reserve credits. When r_1 is further increased to 0.5, the amount of valuable ramping reserve jumps to 479MWh/15min. It means that more available reserves become valuable when the uncertainty level is high. The valuable capacity reserve also increases to 163 MW in this case. A similar tendency can also be observed for the downward reserves shown in Table XIII. It should be emphasized that the amount of valuable reserve does not change monotonically with the uncertainty level. Instead, what we revealed in this paper is a trend.

The available upward ramping reserve and the price of unit 42 are depicted for different time intervals in Fig. 6 with $r_1 = 0.7, r_2 = 1$. As shown in Fig. 6, at t=7, the unit only provides available reserve but not valuable reserve as its price is zero. It can be observed that the ramping reserve price reaches its highest point at t=5, which is also the peak load interval. In contrast, the ramping reserve price is low at t=6 although the load demand at t=6 is still relatively high compared to those at

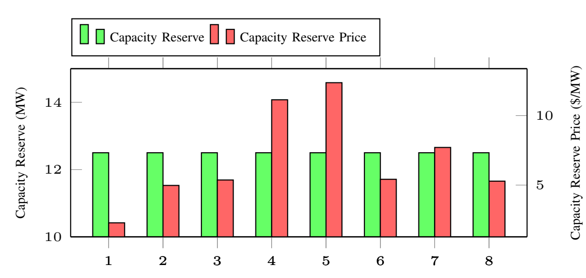

Fig. 7. Upward Capacity Reserve and Price for Unit 24 ($r_1 = 0.7, r_2 = 1$)

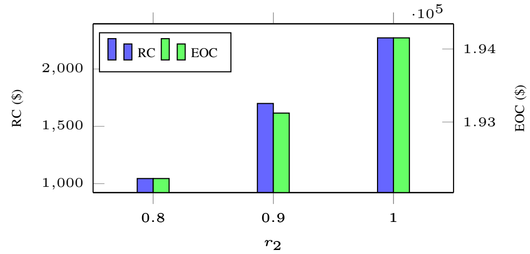

Fig. 8. Reserve Credit (RC) and Expected Operation Cost (EOC) with Different r_2 ($r_1 = 0.6$)

other intervals. It is observed the load climbs from t=4 to t=5, but falls from t=5 to t=6 as shown in Fig. 4. It indicates that the ramping reserve price is related to not only the load demand but also the load change. In this case, the upward ramping reserve is a scarce resource at t=5, and the opportunity cost of keeping them is also high. In contrast, the upward ramping reserve is relatively cheap when the load demand is falling at t=6, t=7, and t=8.

Fig. 7 depicts the available capacity reserve and the price of capacity reserve for unit 24 with $r_1 = 0.7, r_2 = 1$. Although the reserve amount unit 24 keeps is the same at each time interval, the price is different. It is observed that the capacity reserve price in this case has a similar trend to the system load level shown in Fig. 4. For example, the capacity reserve is the most expensive at t=5 when the peak load occurs. The reason is that the system-wide upward capacity reserve is the online installed capacity, which is fixed, less the load level. When the load level is high, the upward capacity reserve is small which becomes a scarce resource in the system.

Reserve credits with respect to different r_2 are presented in Fig. 8. It shows that the decrease of r_2 (from 1 to 0.9 to 0.8) also leads to lower payments related to reserve. For example, when r_2 decreases from 1 to 0.8, the total RC decreases from around \$2,300 to \$1,000. The expected operation cost also decreases from \$194,000 to \$192,000. It indicates that the shrinking uncertainty set actually increases the feasible set for the robust dispatches.

The numerical results in this part indicate that the reserve payment proposed in this paper helps improve the market efficiency. When the uncertainty level is high, the payment related to reserve is also high, It may attract long-term investment of flexible resources. More flexible resources also mean the system has more capabilities to handle the uncertainties, and the system can accommodate higher RES penetrations.

VI. Conclusions

This paper proposes a new concept DRRP within the AARO SCED framework. AARO SCED is an effective tool in RTM to address the uncertainty issue although its solution may only be near-optimal. DRRP in this paper includes the generation ramping reserve and the generation capacity reserve. The prices for DRRP are derived based on the Lagrangian function. They are the opportunity costs of the uncertainty mitigators to keep the reserves or flexibilities. With the help of these prices, the reserves are classified into two categories, which are available reserves and valuable reserves. The case studies explain the concept of these reserves and their impacts on the behaviors of market participants. While the existing FRP may not be able to recover the energy bid cost for generators due to line congestions, the proposed reserve pricing mechanism effectively addresses this issue.

Many research opportunities on this topic are open in the future. With increasing RES penetration in the power system, the flexibilities play a crucial role in uncertainty accommodation. The prices derived in this paper provide an option to determine the reserve signals within the robust optimization framework. Those reserve credits to UMs may attract the investment on flexible resources in the long term. In return, investment on new flexible resources allows the system to accommodate higher RES level. However, we do not consider the cost of the UC, which may prevent some generators from recovering their fixed costs. This leads to another important topic, uplift payment, in the day-ahead market. Convex hull prices and new models are studied in the literature [33]–[36]. It is interesting to investigate the cost recovery considering UC and ramping products in the real-time market.

The most constraints in (16) can be removed based on the analytical conditions in [37]. It is worth mentioning we can provide the solution to (P) as an initial point when solving (MP), which normally leads to better computational performance as most modern solvers support warm-start. These acceleration techniques will be very helpful since it is critical in real-time markets to get a good enough solution within limited time.

It should be pointed out that the reserve prices are unit-specified. It is ideal that all the resources at the same bus have the same price. An extension of the proposed reserve prices is to set the maximum ramping and capacity reserve prices for the units located at a node as the nodal prices. In this way, the nodal reserve prices are determined by the highest opportunity costs for the reserves in the node. It should be also noted that while the robustness against uncertainties is preferred, the robustness does come with a cost and it is widely known that the robust optimization approach is conservative. Accordingly, there should be a trade off between the robustness and the economic effectiveness. In the proposed model, it is possible to formulate a data-driven uncertainty set into the polyhedron in (12) to alleviate the conservativeness. In addition, if a 100% deliverability is not required, we can reduce the confidence level of the nodal uncertainties while keeping the same system-wide confidence level.

It is possible to extend the approach to the day-ahead market. It is noted that one advantage of the proposed approach is the ramping constraints are precise, which is exactly needed in the energy imbalancing market (real-time market). Other researchers propose a multi-stage model with affine policy for the day-ahead unit commitment [16]. However, as the uncertainties are large in day-ahead, if the same ramping constraints are applied in market clearing, then the solution will be more conservative.

As day-ahead market is a financial market, we may use the model with less precise ramping constraints. At the same time, we have more time to calculate the solution in the day-ahead market. Therefore, a potential approach is the two-stage robust model with full recourse actions [38], where the ramping reserves and capacity reserves are combined together. In the day-ahead market, the deliverability of the reserves may lead to the funding deficiency of Financial Transmission Right. Two options are possible. One is to allocate these cost to the LSEs, and the other is to charge the uncertainty source [38].

Appendix A
Lagrangian Function of Problem (P)

$$\begin{aligned}
&\mathcal{L}(\boldsymbol{P_i}, \boldsymbol{G_i}, \boldsymbol{\rho_i}, \boldsymbol{\zeta}, \boldsymbol{\lambda}, \boldsymbol{\gamma}, \boldsymbol{\alpha_i}, \boldsymbol{\beta_i}, \boldsymbol{\eta}, \boldsymbol{\tau}) \qquad (50)\\
=&\sum_i \left(\boldsymbol{P_i}^\top \boldsymbol{Q_i} \boldsymbol{P_i} + \boldsymbol{B_i}^\top \boldsymbol{P_i}\right)\\
&+\boldsymbol{\lambda}^\top\left(\boldsymbol{Dd} - \sum_{\boldsymbol{i}} \boldsymbol{P_i}\right) + \mathrm{Tr}[\boldsymbol{\gamma}^\top(\boldsymbol{D} - \sum_{\boldsymbol{i}} \boldsymbol{G_i})]\\
&+\sum_i \left(\boldsymbol{\alpha_i}^\top(\boldsymbol{AP_i} + \boldsymbol{\rho_i}^\top \boldsymbol{h} - \boldsymbol{R_i}) + \mathrm{Tr}[\boldsymbol{\beta_i}^\top(\boldsymbol{AG_i} - \boldsymbol{\rho_i}^\top \boldsymbol{S})]\right)\\
&+\boldsymbol{\eta}^\top\left(-\boldsymbol{F} - \boldsymbol{\Gamma_d d} + \sum_{\boldsymbol{i}} \boldsymbol{\Gamma_i P_i} + \boldsymbol{\zeta}^\top \boldsymbol{h}\right)\\
&+\ \mathrm{Tr}[\boldsymbol{\tau}^\top\left(\sum_{\boldsymbol{i}} \boldsymbol{\Gamma_i G_i} - \boldsymbol{\Gamma_d} - \boldsymbol{\zeta}^\top \boldsymbol{S}\right)] - \boldsymbol{\xi}^\top \boldsymbol{\rho} - \boldsymbol{\sigma}^\top \boldsymbol{\zeta}
\end{aligned}$$

Appendix B
Derivation of Prices for the First Interval

According to the principle 3) in Section IV and the general idea of the FRP [23], we rewrite the load as

$$d_{m,t} = d_{m,1} + \sum_t \Delta d_{m,t}, \quad t = \{2, 3, \cdots, T\}, \forall m, \qquad (51)$$

and $\Delta d_{m,1} = 0, \forall m$. In FRP [23], a key step to determine the ramping requirement is to get the load change (i.e. load ramping) between intervals. In (51), $\Delta d_{m,t}$ is the load ramping.

As we only settle the first interval, the dispatches in other intervals can be rewritten as

$$P_{i,t} = P_{i,1} + \sum_t \Delta P_{i,t}, \quad t = \{2, 3, \cdots, T\}, \forall i, \qquad (52)$$

and $\Delta P_{i,1} = 0, \forall i$. Only $P_{i,1}$ will be settled, and the dispatches in other intervals are auxiliary. $\Delta P_{i,t}$ can be explained as the reserves. Then, we can reformulate problem (PM) by replacing $d_{m,t}$ and $P_{i,t}$ with (51) and (52). The dual solution to the reformulated problem are the same as that to problem (PM).

Denote $\tilde{\lambda}_t$, $\tilde{\alpha}^{\text{c,u}}_{i,t}$, $\tilde{\alpha}^{\text{c,d}}_{i,t}$, $\tilde{\alpha}^{\text{r,u}}_{i,t}$, $\tilde{\alpha}^{\text{r,d}}_{i,t}$, $\tilde{\eta}^{\text{u}}_{l,t}$, and $\tilde{\eta}^{\text{d}}_{l,t}$ as the dual variables for the load balance constraints, upper and lower bound constraints, upper and lower ramping constraints, upper and lower transmission constraints, respectively. The Lagrangian function of (PM) is

$$\begin{aligned}
&\tilde{\mathcal{L}}(P_{i,1}, \Delta P_{i,t}, \boldsymbol{G}, \boldsymbol{\rho}, \boldsymbol{\zeta}, \tilde{\boldsymbol{\lambda}}, \tilde{\boldsymbol{\gamma}}, \tilde{\boldsymbol{\alpha}}, \tilde{\boldsymbol{\beta}}, \tilde{\boldsymbol{\eta}}, \tilde{\boldsymbol{\tau}})\\
=&\sum_i C(P_{i,1}) + \sum_t \tilde{\lambda}_t \begin{pmatrix} -\sum_i \left(P_{i,1} + \sum_{s=1}^t \Delta P_{i,s}\right) \\ +\sum_m \left(d_{m,1} + \sum_{s=1}^t \Delta d_{m,s}\right) \end{pmatrix}\\
&+\sum_i \sum_t \tilde{\alpha}^{\text{c,u}}_{i,t}(P_{i,1} + \sum_{s=1}^t \Delta P_{i,s} + X_{i,t}(\boldsymbol{\rho}^c) - P_i^{\max})\\
&+\sum_i \sum_t \tilde{\alpha}^{\text{c,d}}_{i,t}(-P_{i,1} - \sum_{s=1}^t \Delta P_{i,s} - X_{i,t}(\boldsymbol{\rho}^c) + P_i^{\min})\\
&+\sum_i \sum_t \tilde{\alpha}^{\text{r,u}}_{i,t}(\Delta P_{i,t} + X_{i,t}(\boldsymbol{\rho}^{\text{r}}) - R_i^{\text{up}})\\
&-\sum_i \sum_t \tilde{\alpha}^{\text{r,d}}_{i,t}(\Delta P_{i,t} + X_{i,t}(\boldsymbol{\rho}^{\text{r}}) + R_i^{\text{down}})\\
&+\sum_l \sum_t \tilde{\eta}^{\text{u}}_{l,t}\left(f_{l,t} + X_{l,t}(\boldsymbol{\zeta}) - \bar{F}_l\right)\\
&-\sum_l \sum_t \tilde{\eta}^{\text{d}}_{l,t}\left(f_{l,t} + X_{l,t}(\boldsymbol{\zeta}) + \bar{F}_l\right)\\
&+\tilde{\mu}\left(\sum_i \sum_t C(P_{i,1} + \sum_{s=1}^t \Delta P_{i,s}) - Z^*(\boldsymbol{d_1})\right) \qquad (53)\\
&+\Xi(\boldsymbol{G}, \boldsymbol{\rho}, \boldsymbol{\zeta}, \tilde{\boldsymbol{\lambda}}, \tilde{\boldsymbol{\gamma}}, \tilde{\boldsymbol{\alpha}}, \tilde{\boldsymbol{\beta}}, \tilde{\boldsymbol{\eta}}, \tilde{\boldsymbol{\tau}}),
\end{aligned}$$

where $X(.)$ is the function of dual variables, and $\Xi(.)$ is the function of adjustment matrices and dual variables. In (53), the objective function in (17) is also rewritten as a function of the dispatches at the first interval $P_{i,1}$. The optimal value of problem (P) is denoted as $Z^*(\boldsymbol{d_1})$, which is a function of the load at the first interval.

Assume that unit i is located at Bus m. We can then derive the price to settle the first interval. It is defined as the additional cost at the first interval due to the unit increment of the load at the first interval with principle 1) in Section IV. Consider the LMP as an example. It can be derived as

$$\frac{\partial \tilde{\mathcal{L}}}{\partial d_{m,1}} = \sum_t \left(\tilde{\lambda}_t - \sum_l \tilde{\eta}^{\text{u}}_{l,t}\Gamma_{l,m} + \sum_l \tilde{\eta}^{\text{d}}_{l,t}\Gamma_{l,m} - \tilde{\mu} \cdot \frac{\partial \mathcal{L}}{\partial d_{m,t}}\right),$$

where $\tilde{\mu} \cdot \frac{\partial \mathcal{L}}{\partial d_{m,t}}$ is from constraint (53). $\frac{\partial \mathcal{L}}{\partial d_{m,t}}$ is actually the LMP derived from (P). The ramping and capacity reserve prices can also be derived similarly.

To have a unified form, we define the intermediate prices

$$\begin{cases}
\tilde{\boldsymbol{\pi}}^{\text{e}}_{\boldsymbol{i,t}} \triangleq [\tilde{\pi}^{\text{e}}_{i,1}, \tilde{\pi}^{\text{e}}_{i,2}, \cdots, \tilde{\pi}^{\text{e}}_{i,T}]^\top\\
\tilde{\boldsymbol{\pi}}^{\text{r,ru}}_{\boldsymbol{i,t}} \triangleq [\tilde{\pi}^{\text{r,ru}}_{i,1}, \tilde{\pi}^{\text{r,ru}}_{i,2}, \cdots, \tilde{\pi}^{\text{r,ru}}_{i,T}]^\top\\
\tilde{\boldsymbol{\pi}}^{\text{r,rd}}_{\boldsymbol{i,t}} \triangleq [\tilde{\pi}^{\text{r,rd}}_{i,1}, \tilde{\pi}^{\text{r,rd}}_{i,2}, \cdots, \tilde{\pi}^{\text{r,rd}}_{i,T}]^\top\\
\tilde{\boldsymbol{\pi}}^{\text{r,cu}}_{\boldsymbol{i,t}} \triangleq [\tilde{\pi}^{\text{r,cu}}_{i,1}, \tilde{\pi}^{\text{r,cu}}_{i,2}, \cdots, \tilde{\pi}^{\text{r,cu}}_{i,T}]^\top\\
\tilde{\boldsymbol{\pi}}^{\text{r,cd}}_{\boldsymbol{i,t}} \triangleq [\tilde{\pi}^{\text{r,cd}}_{i,1}, \tilde{\pi}^{\text{r,cd}}_{i,2}, \cdots, \tilde{\pi}^{\text{r,cd}}_{i,T}]^\top
\end{cases}$$

where

$$\begin{cases}
\tilde{\pi}^{\text{e}}_{i,t} \triangleq \tilde{\lambda}_t - \sum_l \tilde{\eta}^{\text{u}}_{l,t}\Gamma_{l,m} + \sum_l \tilde{\eta}^{\text{d}}_{l,t}\Gamma_{l,m}, \quad \forall t\\
\tilde{\pi}^{\text{r,ru}}_{i,t} \triangleq \tilde{\alpha}^{\text{r,u}}_{i,t}, \quad \tilde{\pi}^{\text{r,rd}}_{i,t} \triangleq \tilde{\alpha}^{\text{r,d}}_{i,t}, \quad \forall t\\
\tilde{\pi}^{\text{r,cu}}_{i,t} \triangleq \tilde{\alpha}^{\text{c,u}}_{i,t}, \quad \tilde{\pi}^{\text{r,cd}}_{i,t} \triangleq \tilde{\alpha}^{\text{c,d}}_{i,t}, \quad \forall t
\end{cases}$$

Based on the intermediate prices, the prices calculated from (P), and the Lagrangian function, the prices in (42)-(46) can be derived based on the sensitivity analysis theory.

It should be emphasized that it is enough to compensate the opportunity costs of generators by crediting the capacity reserves only. In order to be consistent with the existing FRP, generators are also entitled to the ramping reserve credits.

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