This is the author's version of an article that has been published in this journal. Changes were made to this version by the publisher prior to publication.
The final version of record is available at http://dx.doi.org/10.1109/TSTE.2016.2570218

Multiple Period Ramping Processes in Day-Ahead Electricity Markets

Mohammad E. Khodayar, *Member, IEEE,* Saeed D. Manshadi, *Student Member, IEEE,* Hongyu Wu, *Senior Member, IEEE,* and Jeremy Lin, *Senior Member IEEE*

***Abstract*— This paper proposes an approach to formulate the multiple-period ramping capability of dispatchable generation resources and evaluates the impact of this service on the generation scheduling in day-ahead electricity market. It is discussed that the multiple-period ramping enhances the load following capability of dispatchable generation resources and improves the dispatchability of renewable energy resources in power systems. The presented approach encompasses the uncertainties in the operation scheduling of power systems, using scenario based stochastic security-constrained unit commitment (SCUC). The presented case studies also highlight the merits of integrating energy storage facilities to reduce the ramping services provided by dispatchable generation resources with respective costs.**

***Index Terms*: day-ahead market, energy storage, load following, stochastic security constrained unit commitment.**

NOMENCLATURE

<u>Variables and Indices:</u>

b,o	Index of bus
$E_{k,t}^{s}$	Available energy in energy storage
$FRD_{(.),t}^{\mu,s}$	Elastic ramping down service
$FRU_{(.),t}^{\mu,s}$	Elastic ramping up service
$F_{c,j}$	Energy production cost function
$f_{l,t}^{s}$	Power flow of the line
g	Index of resources
j	Index of a thermal unit
k	Index of energy storage facility
$I_{j,t}$	Unit status indicator, 1 means on and 0 means off
$I_{dc,k,t}^{s}, I_{c,k,t}^{s}$	Indicator of discharging and charging modes
l	Index of transmission line
$P_{(.),t}^{s}$	Generation dispatch of a dispatchable unit
$P_{b,t}^{d,s}$	Served demand on bus b
$RD_{j,t}^{\mu,s}, RU_{j,t}^{\mu,s}$	Inelastic ramping down/up service
$RD_{b,t}^{d,\mu,s}$	Served ramping down requirement of demand
$RU_{b,t}^{d,\mu,s}$	Served ramping up requirement of demand
s	Index of scenario
$SD_{j,t}$	Shutdown cost of a unit
$SU_{j,t}$	Startup cost of a unit
$S_{(.),t}^{(.),s}$	Slack variable
t	Hour index
w	Index of wind unit
W_t^s, v_t^s	Value of the objective function for sub-problem
$y_{j,t}, z_{j,t}$	Startup, shutdown indicator of a unit
$\theta_{b,t}^{s}$	Bus voltage angle
$\lambda,\pi,\varphi,\eta,\vartheta,\sigma$ $\psi,\zeta,\delta,\xi,\varsigma,\upsilon$	Lagrange multipliers
μ	Index for ramping up/down process

<u>Constants:</u>

B_b	Set of units connected to bus b
cru_j^{μ}, crd_j^{μ}	Ramping up, ramping down cost
$elast_j^{\mu}$	Elasticity of ramping service of a unit
$E_k^{\min}, E_k^{\max}$	Minimum/maximum energy stored
$L_{f,b}, L_{t,b}$	Set of transmission lines start from/end at bus b
NB	Total number of buses
NG	Total number of units
NK	Total number of energy storage facilities
NL	Total number of transmission lines
NM	Total number ramping processes
NS	Total number scenarios
NT	Total number of hours under study
NW	Total number of wind generation units
$P_j^{\min}, P_j^{\max}$	Minimum/maximum generating capacity
$P_{f,w,t}^{s}$	Forecasted wind generation dispatch
$P_{b,t}^{D,s}$	Demand on bus b

M. E. Khodayar and S. D. Manshadi are with Electrical Engineering Department, Southern Methodist University, Dallas, TX. 75205 USA. (e-mail: mkhodayar@lyle.smu.edu, and manshadi@smu.edu). H. Wu is with the Power Systems Engineering Center at the National Renewable Energy Laboratory, Golden, CO 80401 USA (e-mail: hongyu.wu@nrel.gov). J. Lin is with PJM Interconnection, Audubon, PA 19403, USA (e-mail: Jeremy.Lin@pjm.com). The views presented in this paper do not necessarily represent those of the PJM Interconnection.

$P_{(.),k}^{\min}, P_{(.),k}^{\max}$	Minimum/maximum discharging and charging capacity
$f_l^{\max}$	Maximum capacity of transmission line
$RD_j^{\mu,\max}$	Maximum ramping down service
$RU_j^{\mu,\max}$	Maximum ramping up service
$RD_{b,t}^{D,\mu,s}$	Ramping down requirement of demand
$RU_{b,t}^{D,\mu,s}$	Ramping up requirement of demand
$UG_{j,t}^{s}$	Outage indicator, 1 if available, 0 otherwise
$\alpha_j, \beta_j, \gamma_j$	Coefficients for generation cost function
$x_{b,o}$	Inductive reactance of transmission line
κ_b^D	Value of lost load
κ_b^μ	Value of unserved ramping requirement
ρ^s	Probability of scenario s
τ_μ	Ramping time span

I. Introduction

In power networks with renewable energy sources (RES), the net demand is determined as the total demand minus the total RES generation. Some research efforts have been made to address the net demand following services with considerable penetration of RES [1]-[5]. The integration of larger amount of RES increases the required ramping and load following services in the electricity networks. The impacts of such ramping services on the thermal generation scheduling in the deregulated environment were addressed in [6]-[15]. In [6], it was shown that the power networks with higher penetration of RES require higher ramping services, which are provided by dispatchable generation units in the network. In [7], the impact of ramping costs on the generation scheduling of the thermal units was evaluated considering the hourly time spans for ramping processes. In [8], an approach to incorporate the ramping costs in the strategic self-dispatching of a generation company (GENCO) was presented, where the impact of the strategic selection of ramping process on the payoff of the generator was discussed. The selected ramping process imposed ramping cost as a result of excursion of the dispatch beyond the elastic range; however, neither the effect of ramping processes on the generation scheduling nor the capability of providing multiple ramping services by a generation unit was addressed in [8].

Maintaining sufficient ramping capacity is crucial to net demand following services in the real-time power system operation. Failure to do so may result in loss of load and real-time scarcity events. Recent research has highlighted the importance of ramping capabilities in the power system operation. In [9], the ramping limit of generation unit was presented as a function of generation dispatch of the unit, which was further approximated by a piecewise linear function. The impact of ramping cost on the day-ahead scheduling was studied in our previous work [10], where a single-period ramping process for the generation resources was proposed without consideration of any uncertainty in power system operation. The effects of integrating RES on the ramping cost of the thermal generation units were addressed in [11]. It was stated that the energy storage facilities reduce the variability of wind generation as well as the ramping costs associated with the wind variability. Dynamic modeling of cycling cost including the ramping services in [12] mitigates the wear and tear of generators and consequently reduces the operation cost of the system. The impact of the ramping cost on economic dispatch with high penetration of renewable energy resources is addressed in [13]. Here, the economic benefits of ramping services for customers and generators were captured in the proposed market settlement. The ramping cost varies with the generation technology as a result of thermal and mechanical stresses [14]. In [15], a framework was proposed to charge the market participants who increase the net demand fluctuation in the network and implementing this framework eventually led to the flexibility and ramping cost reduction in the network. A systematic framework for characterizing the net demand volatility to evaluate the day-ahead flexibility requirements of power system was addressed in [16]. The flexibility requirement for an operational planning framework is procured by introducing the flexibility envelopes that capture the potential intra-hour variability and uncertainty of net demand in power systems [17]. It is concluded that determining the flexibility requirements would decrease the load curtailment in the power networks with volatile renewable energy resources. Such flexibility requirements are served using single period ramping services supplied by dispatchable generation units.

Several advanced optimization approaches including scenario-based stochastic optimization, robust optimization, and interval optimization are employed to manage the increasing uncertainty of demand and renewable energy resources in the power system operation. The improved interval unit commitment (IIUC) is proposed in [18] to capture the ramping requirement in worst scenarios. In [19], the economic dispatch is formulated as a robust optimization problem to determine the required ramping capacity to compensate for the uncertainties in the net demand.

In this paper, the ramping processes for generation units are presented in multiple time spans. The GENCOs submit bids for offering ramping services in certain ramping time spans, based on which the independent system operator (ISO) clears the day-ahead market and ensures the adequacy of the generation resources to supply the net demand. The salient feature of the proposed multi-period ramping processes is that it could provide additional ramping flexibility for ISOs to balance the generation and load beyond the regulation response time. It is then embedded in the scenario-based stochastic security-constrained unit commitment (S-SCUC) approach, to encompass various uncertainties in the power systems operation. Case studies are conducted in a 6-bus system and an IEEE 118-bus system, where the benefit of integrating the multi-period ramping process is clearly shown.

The proposed approach of scheduling the multi-period ramping services in response to the uncertainty of the load and variable generation can be seamlessly integrated into the day-ahead market or utility operations, where thermal generating units are allowed to ramp up/down during the first and last few minutes of an hourly time interval. The contributions of this paper are highlighted as follows:

- Novel multi-period ramping services of the generation units are formulated in stochastic day-ahead SCUC, taking into account the forecast errors of demand and wind generation, and random outage of the system components.
- The effect of multiple-period ramping services on the dispatchability of the renewable energy resources and reduction of inelastic ramping costs are presented.
- The impact of renewable generation on multiple-period ramping requirements of power system is analyzed.
- The impact of storage facilities on the generation dispatch profile and the ramping requirements served by dispatchable generation resources are evaluated.

The rest of the paper is organized as follows. The multiple-time ramping processes are presented in Section II. The day-ahead market operation with multiple-period ramping processes is formulated in Section III. The numerical results are presented and analyzed in Section IV and the conclusions are drawn in Section V.

II. Multiple-period Ramping Processes

The variation in the dispatch of thermal generation unit increases the stress on the rotor shaft and escalates the rotor fatigue. Traditionally, ramping constraints were imposed as the limitation on dispatch changes in consecutive time periods, where the ramping excursion should be within the determined elastic range (ER) with no associated cost [21]-[25]. However, this may constrain the committed generating resources from providing additional ramping services, which in turn commits/dispatches more expensive units to follow the fast-varying net demand [8], [20].

The negative impact of ramping on the thermal unit's lifetime could be captured by introducing the ramping cost in the generation scheduling problem [7]. The ramping cost is incurred when the variations in the generation dispatch fall beyond the determined ER, which are further characterized by the realized ramping rates and ramping times (usually in minutes). As shown in Fig. 1, the ER is increased with the increase in ramping time and the ramping cost for a generator increases as the ramping time decreases. The ramping service could exceed the ER as long as a proper incentive is in place for compensating its adverse impacts on the unit's lifetime. This will increase the operational flexibility of power systems and efficiently avoid ramping capacity shortages and short-term scarcity events.

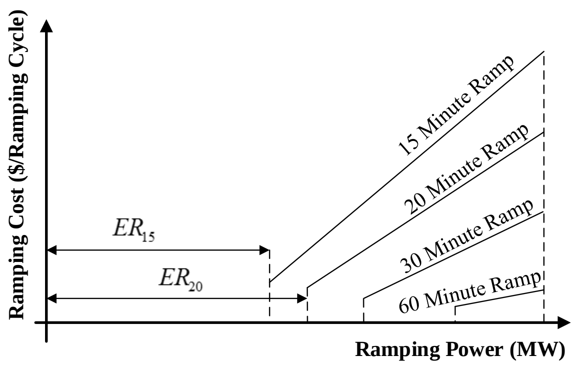

Fig. 1. Ramping costs for multiple period ramping processes

In power system operation, the total ramping services provided by dispatchable units should be no less than the total ramping requirement of the net demand. In order to meet this requirement, ramping services are modeled here at different ramping times to serve the demand with diverse ramping requirements. Fig. 2 shows the generation dispatch profile with multiple-period ramping services for four consecutive periods. The generation dispatch profile provides multiple ramping services with corresponding ramping times. In Fig. 2, the ramping up (RU) services at $t-1$ are RU_{t-1}^{1} and RU_{t-1}^{4} with ramping times τ_1 (60-min) and τ_4 (15-min), respectively. The ramping service during τ_4 is the algebraic sum of RU_{t-1}^{1} and RU_{t-1}^{4}. Here, the ramping down (RD) services at $t+1$ are RD_{t+1}^{2} and RD_{t+1}^{3} with ramping times τ_2 (30-min) and τ_3 (20-min), respectively. Therefore, the generator provides both 15-min and 60-min RU services at $t-1$ to reach its scheduled dispatch.

It is worth mentioning that the time period for the load following service is on the minute timescale. The proposed approach is not intended to address very large disruptions in power balance, which usually occurs in case of a generator outage, and/or sudden abruption in renewable energy resources or demand. The sudden disturbance in supply and demand balance is managed by deploying the operating reserves, such as non-spinning and replacement reserves. In contrast, the proposed approach addresses the response of the supply under smaller variations and uncertainties, and determines the ramping capability in dispatchable resources to ensure the adequacy in the system. Here, ramping curtailment shows an unsuccessful load following practice, which leads to demand curtailment as a result of the mismatch between the provided ramping services and the required ramping capacities. The presented framework for multiple-period ramping services can be extended to the real-time operation with "flexiramp" product [26]-[28]. The "flexiramp" service is

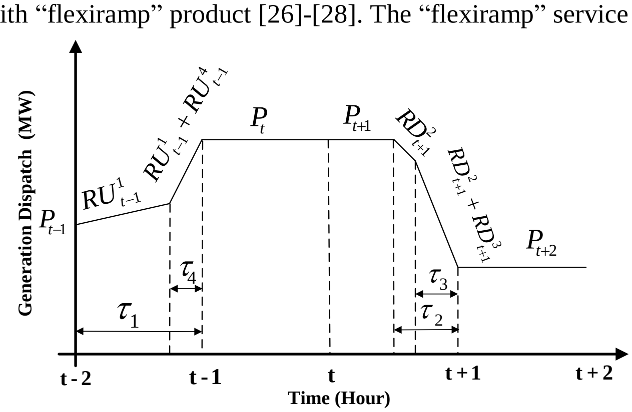

Fig. 2. Generation dispatch profile with respective ramping services

introduced to reduce the computation burden associated with stochastic programming framework for capturing the uncertainties in real-time operation.

III. Problem Formulation

The proposed formulation is a mixed-integer programming (MIP) problem, and the proposed approach to solve this problem leverages Benders decomposition technique as shown in Fig. 3. The proposed stochastic multiple-period ramping process can be included in any existing day-ahead market clearing process and solved by any prevailing solution method, e.g., Branch and Bound, Benders Decomposition (BD), Progressive Hedging (PH), and Lagrangian Relaxation (LR), etc. Here, Benders decomposition technique is utilized to solve the proposed MIP problem [29]-[31]. The problem is decomposed into a master problem and multiple sub-problems for each time step and scenario. As shown in Fig. 3, in the first sub-problem, the demand and supply balance at each time step is evaluated considering the limitations on the transmission lines and dc power flow constraints. The second sub-problem determines the balance between the RU and RD services and requirements. Here, the master problem presents the unit commitment and economic dispatch in power system. Two sub-problems evaluate the demand/supply balance in inner loop and ramping up/down balance in outer loop as shown in Fig. 3.

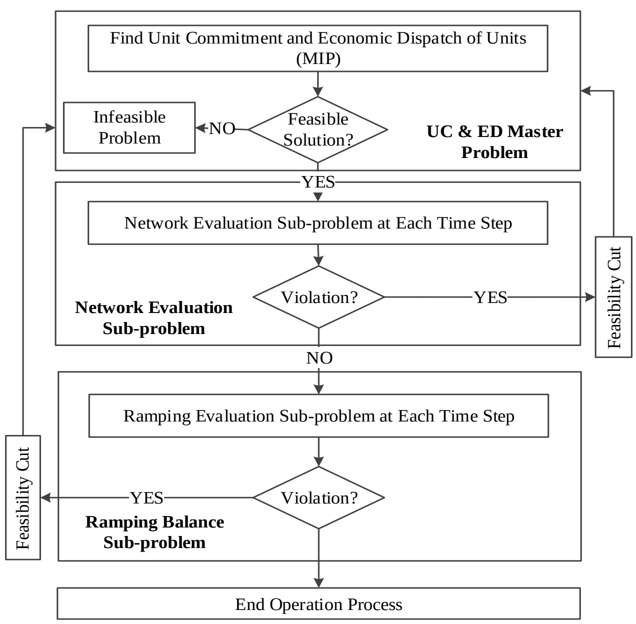

Fig. 3. The flow chart of the proposed solution framework

Feasibility cuts are generated and sent back to the master problem in case the solution of the master problem cannot satisfy the transmission line capacity constraints and dc power flow constrains. The solution of the master problem will be updated in the next iteration until no violation exists in the first sub-problem (inner loop). At this stage, the solution is passed to the second sub-problem to check for the demand and generation ramping balance. Similarly, if any violation exists, feasibility cuts are added to the master problem and the solution of the master problem is updated until there are no violations in the first and second sub-problems (outer loop). The mathematical formulations for the master problem and sub-problems are presented in this section.

A. Unit Commitment and Economic Dispatch Master Problem

The master problem is formulated as a MIP problem shown in (1) – (23). The objective function, which is shown in (1), is the total operation cost of the system including the operation cost of the generators, as well as the penalty for the demand curtailment. The first term in the objective function represents the operation cost as well as the startup and shutdown costs of the generators. The second two terms represent the RU and RD costs of the generators, respectively. The last term is the penalty associated with the hourly demand curtailment and the deficiencies in providing the ramping requirement by the generation resources. In this formulation, the curtailed demand and the curtailed ramping requirements have respective penalty values. Since ramping curtailment also contributes to the demand curtailment, the ramping curtailment penalty could be determined from the demand curtailment penalty. Here, the demand curtailment as a result of deficiency in ramping capability of the generation resources is differentiated from the demand curtailment caused by the deficiency in the generation dispatch. The ramping curtailment penalty is expected to be lower than the demand curtailment penalty. The objective function is subjected to several generation unit and network constraints as shown in (2)-(23).

The quadratic cost function of each unit for supplying energy is shown in (2). The constraints on the dispatch of each generator are shown in (3). The startup and shutdown costs of the generators as well as the minimum on-time and minimum off-time of the generation units are considered in this formulation [30]. The elastic and inelastic RU constraints for each RU process are shown in (4) and (5), respectively. Here, M is a large constant number. As shown in these constraints, the RU service is divided into free elastic ramping service, and inelastic RU service, which is associated with the respective costs. The free RU service is limited by the ER if the unit is neither starting up/shutting down nor is on outage. Similar formulations for RD services are shown in (6) and (7). In (8), the relationship between ramping processes and the generation dispatch is shown.

$$Min\sum_{t=1}^{NT}\sum_{s}^{NS}\rho^{s}\left(\begin{array}{l}\sum_{j=1}^{NG}\left[\begin{array}{l}F_{c,j}\left(P_{j,t}^{s},RU_{j,t}^{\mu,s},RD_{j,t}^{\mu,s}\right)+SU_{j,t}+SD_{j,t}+\\ \sum_{\mu=1}cru_{j}^{\mu}.RU_{j,t}^{\mu,s}+crd_{j}^{\mu}.RD_{j,t}^{\mu,s}\end{array}\right]+\\ \sum_{b=1}^{NB}\left[\begin{array}{l}\kappa_{b}^{D}\left(P_{b,t}^{D,s}-P_{b,t}^{d,s}\right)+\\ \sum_{\mu=1}^{NM}(\kappa_{b}^{\mu}-\frac{\kappa_{b}^{D}}{2}\tau_{\mu}^{2})\left(\begin{array}{l}\left|RU_{b,t+1}^{D,\mu,s}-RU_{b,t+1}^{d,\mu,s}\right|\\ +\left|RD_{b,t+1}^{D,\mu,s}-RD_{b,t+1}^{d,\mu,s}\right|\end{array}\right)\end{array}\right]\end{array}\right) \tag{1}$$

$$F_{c,j}\left(P_{j,t}^{s},RU_{j,t}^{\mu,s},RD_{j,t}^{\mu,s}\right)=\left[\begin{array}{l}\alpha_{j}\left(P_{j,t}^{s}+\frac{1}{2}\sum_{\mu}\tau_{\mu}^{2}(RU_{j,t+1}^{\mu,s}-RD_{j,t+1}^{\mu,s})\right)^{2}+\\ \beta_{j}\left(P_{j,t}^{s}+\frac{1}{2}\sum_{\mu}\tau_{\mu}^{2}(RU_{j,t+1}^{\mu,s}-RD_{j,t+1}^{\mu,s})\right)+\gamma_{j}\end{array}\right] \tag{2}$$

This is the author's version of an article that has been published in this journal. Changes were made to this version by the publisher prior to publication.
The final version of record is available at http://dx.doi.org/10.1109/TSTE.2016.2570218

$$P_j^{\min}\cdot I_{j,t}\le P_{j,t}^s\le P_j^{\max}\cdot I_{j,t} \tag{3}$$

$$0\le\tau_\mu FRU_{j,t}^{\mu,s}\le RU_j^{\mu,\max}.elast_j^\mu+M(1-UG_{j,t}^s+y_{j,t}) \tag{4}$$

$$0\le\tau_\mu RU_{j,t}^{\mu,s}\le RU_j^{\mu,\max}(1-elast_j^\mu) \tag{5}$$

$$0\le\tau_\mu FRD_{j,t}^{\mu,s}\le RD_j^{\mu,\max}.elast_j^\mu+M(1-UG_{j,t}^s+z_{j,t}) \tag{6}$$

$$0\le\tau_\mu RD_{j,t}^{\mu,s}\le RD_j^{\mu,\max}(1-elast_j^\mu) \tag{7}$$

$$\sum_{\mu=1}^{NM}\tau_\mu\left[(RU_{j,t}^{\mu,s}+FRU_{j,t}^{\mu,s})-(RD_{j,t}^{\mu,s}+FRD_{j,t}^{\mu,s})\right]=P_{j,t}^s-P_{j,t-1}^s \tag{8}$$

$$\sum_{\mu}^{NM}\tau_\mu(RU_{b,t}^{d,\mu,s}-RD_{b,t}^{d,\mu,s})=P_{b,t}^{d,s}-P_{b,t-1}^{d,s} \tag{9}$$

$$0\le P_{b,t}^{d,s}\le P_{b,t}^{D,s} \tag{10}$$

$$0\le P_{w,t}^s\le P_{f,w,t}^s \tag{11}$$

$$P_{k,t}^s=P_{dc,k,t}^s-P_{c,k,t}^s \tag{12}$$

$$I_{c,k,t}^s\cdot P_{c,k}^{\min}\le P_{c,k,t}^s\le I_{c,k,t}^s\cdot P_{c,k}^{\max} \tag{13}$$

$$I_{dc,k,t}^s+I_{c,k,t}^s\le 1 \tag{14}$$

$$\begin{aligned}&\sum_{\mu}^{NM}\tau_\mu\left(FRU_{dc,k,t}^{\mu,s}+FRD_{c,k,t}^{\mu,s}-(FRD_{dc,k,t}^{\mu,s}+FRU_{c,k,t}^{\mu,s})\right)\\&=P_{k,t}^s-P_{k,t-1}^s\end{aligned} \tag{15}$$

$$\sum_{\mu}^{NM}\tau_\mu(FRU_{dc,k,t}^{\mu,s}-FRD_{dc,k,t}^{\mu,s})=P_{dc,k,t}^s-P_{dc,k,t-1}^s \tag{16}$$

$$\sum_{\mu}^{NM}\tau_\mu(FRU_{c,k,t}^{\mu,s}-FRD_{c,k,t}^{\mu,s})=P_{c,k,t}^s-P_{c,k,t-1}^s \tag{17}$$

$$E_k^{\min}\le E_{k,t}^s\le E_k^{\max} \tag{18}$$

$$E_{k,t}^s=E_{k,t-1}^s-\left(\begin{array}{c}\dfrac{P_{dc,k,t}^s+\frac{1}{2}\sum_{\mu}\tau_\mu{}^2(FRU_{dc,k,t+1}^{\mu,s}-FRD_{dc,k,t+1}^{\mu,s})}{\eta_{dc}^k}\\ -\eta_c^k\cdot(P_{c,k,t}^s+\frac{1}{2}\sum_{\mu}\tau_\mu{}^2(FRU_{c,k,t+1}^{\mu,s}-FRD_{c,k,t+1}^{\mu,s}))\end{array}\right) \tag{19}$$

$$P_{j,t-1}^s-P_{j,t}^s\le P_j^{\min}z_{j,t}+\tau_\mu\cdot RD_j^{\mu,\max}(1-z_{j,t}) \tag{20}$$

$$\begin{aligned}&0\le P_{b,t}^{d,s}+\sum_{\mu}^{NM}\frac{1}{2}\tau_\mu{}^2(RU_{b,t+1}^{d,\mu,s}-RD_{b,t+1}^{d,\mu,s})\le\\&P_{b,t}^{D,s}+\sum_{\mu}^{NM}\frac{1}{2}\tau_\mu{}^2(RU_{b,t+1}^{D,\mu,s}-RD_{b,t+1}^{D,\mu,s})\end{aligned} \tag{21}$$

$$I_{j,t}-I_{j,t-1}=y_{j,t}-z_{j,t} \tag{22}$$

$$y_{j,t}+z_{j,t}\le 1 \tag{23}$$

In (9), the relationship between the served ramping requirement and the served demand is shown. Similar formulation is applied for wind generation with respective index. The maximum and minimum limitations on the served demand and the dispatched wind generation are given in (10) and (11), respectively. The dispatch of the energy storage facility is shown in (12). The charging dispatch of the energy storage unit is limited by (13). Similar constraint is applied to the discharging dispatch. The charging and discharging states of the energy storage unit is mutually exclusive which is shown in (14). The relationship between the RU and RD services and the dispatch of the energy storage unit in charging and discharging states are shown in (15)-(17). The limits on the energy stored in the energy storage facility are imposed by (18). The hourly stored energy in the energy storage unit is shown in (19). Constraint (20) indicates that the generation units will reach the minimum dispatch before shutting down. Similar formulation is applied to the startup process. The served demand is less than or equal to the total demand considering the respective ramping requirements as shown in (21). The relationship between startup and shutdown indicators and commitment status indicator is given in (22). As shown in (23), the startup and shutdown states of a unit are mutually exclusive.

B. Network Evaluation Sub-problem

In this sub-problem, the balance between the generation and demand at each bus is evaluated considering the dc power flow constraints and transmission line limits. The problem formulation is shown in (24)-(29). In network evaluation sub-problem, the commitment and dispatch procured from the master problem are used to form a linear programming (LP) problem, to check network security constraints. The objective given in (24) is to minimize nodal violations in supply and demand. The power balance at each node is shown in (25) considering the possible mismatches between the generation and demand. The power transmitted by the transmission line is dependent on the difference in bus voltage angles and the inductive reactance of the transmission line as shown in (26). The limits on the transmitted power through the transmission line are shown in (27). Here, $\hat{P}_{(.)}^{(.)}$ is the procured generation dispatch and the served demand in the master problem, and $\iota_{(.)}^{(.)}$ and $\upsilon_{(.)}^{(.)}$ are the Lagrange multipliers for constrains (28) and (29), respectively. If the value of (24) is higher than specified tolerance, the current solution from master problem violates the generation and demand balance and feasibility cuts (30) are formed and added to the master problem. The master problem is solved again with the new constraints and this iterative process continues until there is no violation in this sub-problem. The solution is then passed to the next sub-problem (i.e. ramping balance sub-problem) describe in the next section.

$$Min\ \ v_t^s=\sum_b^{NB}\left(S_{b,t}^{1,s}+S_{b,t}^{2,s}\right) \tag{24}$$

$$\begin{aligned}&\sum_{j\in B_b}P_{j,t}^s+\sum_{w\in B_b}P_{w,t}^s+\sum_{k\in B_b}P_{k,t}^s+S_{b,t}^{1,s}-S_{b,t}^{2,s}\\&=P_{b,t}^{d,s}+\sum_{l\in L_{f,b}}fl_{l,t}^s-\sum_{l\in L_{t,b}}fl_{l,t}^s\end{aligned} \tag{25}$$

$$fl_{l,t}^s=\frac{\theta_{b,t}^s-\theta_{o,t}^s}{x_{b,o}}\qquad l\in\{b-o\} \tag{26}$$

$$\left|fl_{l,t}^s\right|\le fl_l^{\max} \tag{27}$$

$$P_{g,t}^s=\hat{P}_{g,t}^s\qquad \iota_{g,t}^s,\ g\in\{j,w,k\} \tag{28}$$

$$P_{b,t}^{d,s}=\hat{P}_{b,t}^{d,s}\qquad \upsilon_{b,t}^s \tag{29}$$

$$\hat{v}_t^s+\sum_g\iota_{g,t}^s(P_{g,t}^s-\hat{P}_{g,t}^s)+\sum_b\upsilon_{b,t}^s(P_{b,t}^{d,s}-\hat{P}_{b,t}^{d,s})\le 0 \tag{30}$$

A. *Ramping Balance Sub-problem*

In this sub-problem, the balance between the generation and demand ramping is evaluated using (31)-(43). The dispatch vector procured from the master problem is utilized to check the generation and demand ramping balance. The problem is formulated as LP problem with the objective given in (31). The objective is to minimize the mismatch in RU and RD of the generation and demand subjected to respective RU and RD constraints. The RU and RD balances between the generation and demand are shown in (32) and (33) respectively, considering the introduced mismatches. The total ramping service provided by generators, wind generation and energy storage unit is equal to the ramping required by the demand. Here $\hat{P}_{(.)}^{(.)}$, $\hat{R}U_{(.)}^{(.)}$, $F\hat{R}U_{(.)}^{(.)}$, $\hat{R}D_{(.)}^{(.)}$, and $F\hat{R}D_{(.)}^{(.)}$ are the procured generation dispatch and RU and RD services from the master problem. In addition, $\lambda_{g,t}^{\mu,s}$, $\varphi_{j,t}^{\mu,s}$, $\pi_{g,t}^{\mu,s}$, $\eta_{j,t}^{\mu,s}$, $\psi_{dc,k,t}^{\mu,s}$, $\zeta_{c,k,t}^{\mu,s}$, $\xi_{dc,k,t}^{\mu,s}$, $\delta_{c,k,t}^{\mu,s}$, $\sigma_{b,t}^{\mu,s}$, and $\vartheta_{b,t}^{\mu,s}$ are the Lagrange multipliers of the constraints (34) – (43) respectively. If the value of (31) is higher than a specified tolerance, the current solution from master problem violates the generation and demand ramping balance. Thus, feasibility cuts (44) are formed and added to the master problem. This iterative process continues until no violation exists in this sub-problem.

$$Min\ \ w_t^s=\sum_{\mu}^{NM}\left(S_{1,t}^{\mu,s}+S_{2,t}^{\mu,s}+S_{3,t}^{\mu,s}+S_{4,t}^{\mu,s}\right) \tag{31}$$

$$\begin{aligned}&\sum_{i}^{NG}(RU_{j,t}^{\mu,s}+FRU_{j,t}^{\mu,s})+\sum_{w}^{NW}FRU_{w,t}^{\mu,s}+\sum_{k}^{NK}FRU_{dc,k,t}^{\mu,s}+S_{1,t}^{\mu,s}-S_{2,t}^{\mu,s}\\&=\sum_{b}^{NB}RU_{b,t}^{d,\mu,s}+\sum_{k}^{NK}FRU_{c,k,t}^{\mu,s}\end{aligned} \tag{32}$$

$$\begin{aligned}&\sum_{i}^{NG}(RD_{j,t}^{\mu,s}+FRD_{j,t}^{\mu,s})+\sum_{w}^{NW}FRD_{w,t}^{\mu,s}+\sum_{k}^{NK}FRD_{dc,k,t}^{\mu,s}+S_{3,t}^{\mu,s}-S_{4,t}^{\mu,s}\\&=\sum_{b}^{NB}RD_{b,t}^{d,\mu,s}+\sum_{k}^{NK}FRD_{c,k,t}^{\mu,s}\end{aligned} \tag{33}$$

$$FRU_{g,t}^{\mu,s}=F\hat{R}U_{g,t}^{\mu,s} \qquad \lambda_{g,t}^{\mu,s},\ g\in\{j,w\} \tag{34}$$

$$RU_{j,t}^{\mu,s}=\hat{R}U_{j,t}^{\mu,s} \qquad \varphi_{j,t}^{\mu,s} \tag{35}$$

$$FRD_{g,t}^{\mu,s}=F\hat{R}D_{g,t}^{\mu,s} \qquad \pi_{g,t}^{\mu,s},\ g\in\{j,w\} \tag{36}$$

$$RD_{j,t}^{\mu,s}=\hat{R}D_{j,t}^{\mu,s} \qquad \eta_{j,t}^{\mu,s} \tag{37}$$

$$FRU_{dc,k,t}^{\mu,s}=F\hat{R}U_{dc,k,t}^{\mu,s} \qquad \psi_{dc,k,t}^{\mu,s} \tag{38}$$

$$FRU_{c,k,t}^{\mu,s}=F\hat{R}U_{c,k,t}^{\mu,s} \qquad \zeta_{c,k,t}^{\mu,s} \tag{39}$$

$$FRD_{dc,k,t}^{\mu,s}=F\hat{R}D_{dc,k,t}^{\mu,s} \qquad \xi_{dc,k,t}^{\mu,s} \tag{40}$$

$$FRD_{c,k,t}^{\mu,s}=F\hat{R}D_{c,k,t}^{\mu,s} \qquad \delta_{c,k,t}^{\mu,s} \tag{41}$$

$$RD_{b,t}^{d,\mu,s}=\hat{R}D_{b,t}^{d,\mu,s} \qquad \sigma_{b,t}^{\mu,s} \tag{42}$$

$$RU_{b,t}^{d,\mu,s}=\hat{R}U_{b,t}^{d,\mu,s} \qquad \vartheta_{b,t}^{\mu,s} \tag{43}$$

$$\begin{aligned}&\hat{w}_t^s+\sum_{g}\lambda_{g,t}^{\mu,s}(FRU_{g,t}^{\mu,s}-F\hat{R}U_{g,t}^{\mu,s})+\pi_{g,t}^{\mu,s}(FRD_{g,t}^{\mu,s}-F\hat{R}D_{g,t}^{\mu,s})+\\&\sum_{b}\vartheta_{b,t}^{\mu,s}(RU_{b,t}^{d,\mu,s}-\hat{R}U_{b,t}^{d,\mu,s})+\sigma_{b,t}^{\mu,s}(RD_{b,t}^{d,\mu,s}-\hat{R}D_{b,t}^{d,\mu,s})+\\&\sum_{j}\varphi_{j,t}^{\mu,s}(RU_{j,t}^{\mu,s}-\hat{R}U_{j,t}^{\mu,s})+\eta_{j,t}^{\mu,s}(RD_{j,t}^{\mu,s}-\hat{R}D_{j,t}^{\mu,s})+\\&\sum_{k}\begin{array}{l}\psi_{dc,k,t}^{\mu,s}(FRU_{dc,k,t}^{\mu,s}-F\hat{R}U_{dc,k,t}^{\mu,s})+\xi_{dc,k,t}^{\mu,s}(FRD_{dc,k,t}^{\mu,s}-F\hat{R}D_{dc,k,t}^{\mu,s})\\+\zeta_{c,k,t}^{\mu,s}(FRU_{c,k,t}^{\mu,s}-F\hat{R}U_{c,k,t}^{\mu,s})+\delta_{c,k,t}^{\mu,s}(FRD_{c,k,t}^{\mu,s}-F\hat{R}D_{c,k,t}^{\mu,s})\end{array}\le 0\end{aligned} \tag{44}$$

IV. Case Study

A. *Scenario generation and reduction*

In this paper, Monte Carlo simulation is used to generate 3,000 scenarios considering the uncertainty in the demand, the outage of the transmission lines and generation units as well as the availability of the renewable energy resources. Truncated normal distribution function is employed to determine the forecast error of the demand, where the mean value is the forecasted demand and the standard deviation is certain percentage of the mean values [32], [33]. Here, the standard deviation of 5% of the mean value.

In this paper, ARMA (1,1) is used for capturing uncertainties in the wind speed time series. Wind speed time series is simulated using the Weibull distribution function, auto correlation factor and diurnal pattern by forming the transition probability matrices [34]. Further details on generating the wind speed time series using the probability transition matrix is described in [35]. The alternate method was to use a historical data of wind speed time series and present the uncertainties in wind speed time series using ARMA (1,1) [36], which is further validated in [37]. Several papers addressed the forecast error in wind power generation [38]-[46] using Gaussian distribution [40], β-distribution [41], Weibull distribution [42], γ-distribution [43], Cauchy distribution [44], and Levy α-stable distribution [45]. The accuracy of wind speed forecast error for Auto-Regressive (AR), Moving-Average (MA), and ARMA are compared in [38]-[39]. While MA is simpler to implement, ARMA is recommended as a more accurate and reliable tool in these papers.

Since the auto correlation factor (ACF) and partial autocorrelation factor (PACF) of the wind speed time series decrease dramatically as the time lag increases, the wind speed forecast error is represented by a lower order ARMA (1,1) as shown in (45). In this paper, it is assumed that the ARMA constants are $\alpha=0.98$ and $\beta=-0.7$, and $Z(t)$ follows a Gaussian distribution function with a standard deviation equal to 10% of the wind speed forecast. The ramping requirement corresponds to each ramping time is calculated based on the demand and renewable generation profiles. Here, the ramping times are determined in base case, and the ramping requirements correspond to each ramping time will change in each scenario based on the forecast errors.

$$X(t)=\alpha\cdot X(t-1)+\beta\cdot Z(t-1)+Z(t) \tag{45}$$

To address the outage of generation and transmission units, the outage replacement rate (ORR) is used [32]. The probability of failure follows the exponential probability distribution and it is assumed that once an outage occurs, the corresponding component remains unavailable for the rest of the operation period. Hence, the probability of outage is a function of the failure rate (λ) and the lead time (t), as given in (46). Since $\lambda t \ll 1$ for a day-ahead operation problem, the probability of outage for each component is represented by (47) which is referred to as the ORR of the component. Here, the failure rates for the generation units and transmission lines are 2.8 f/yr ($\lambda=0.000319$) and 1.2 f/yr ($\lambda=0.000136$) respectively.

$$P\{Outage\} = 1 - e^{-\lambda t} \tag{46}$$

$$ORR = P\{Outage\} = \lambda t \tag{47}$$

Several scenario reduction techniques including fast backward, fast backward /forward and fast backward/backward were presented to reduce the number of effective scenarios by merging the scenarios with similar metrics. The forward method provides better accuracy at the cost of high computation time when the number of preserved scenarios is small. Fast backward method has less computation time with less accuracy for large scenario trees. The fast backward/forward method improves the speed and accuracy of scenario reduction compared to forward and backward methods. Hence, this technique is utilized to procure five and twelve distinct scenarios for IEEE 118-bus power system and sample 6-bus power system, respectively [47], [48]. In this approach, the scenarios with closer measures are clustered to form a new scenario with the probability equal to the sum of the probability of all clustered scenarios. The wind generation, and demand data are normalized to construct a set of data in scenario tree.

In this case study, the deterministic case is the scenario with highest probability. Capturing larger number of scenarios will increase the computation burden, which requires more processing and memory resources. Such cases with larger number of scenarios may be solved utilizing parallel processing using multiple CPU cores.

B. 6-bus Power System

In this section, a 6-bus power system that is composed of three thermal generation units and one wind unit is considered. The characteristics of the transmission line and the thermal generation units are shown in Tables I and II, respectively. The generation units G1, G2, and G3, are connected to buses 1, 2, and 6 respectively. The wind generation is connected to bus 3 and the loads are served on buses 3, 4, 5, and 6. The wind generation (W1) capacity is 75 MW and the penetration level of wind generation is 22.13%. The RU limits for G1, G2, and G3 are 60 MW/h, 40 MW/h, and 20 MW/h, respectively. The RD limits for G1, G2, and G3 are, respectively, 50 MW/h, 40 MW/h, and 10 MW/h. The elasticity of ramping service for G1, G2, and G3 are assumed 40%, 40%, and 30%, respectively. It is assumed that there is no ramping limit and no ramping cost for the energy storage unit at bus 3 and the minimum and maximum energy stored is 10 MWh and 200 MWh, respectively. The minimum and maximum charging and discharging dispatch of the energy storage unit is 0 MW and 80 MW, respectively.

TABLE I
TRANSMISSION LINE CHARACTERISTICS

Line ID	From Bus	To Bus	Impedance (p.u.)	Maximum Power Flow (MW)
1	1	2	0.170	100
2	1	4	0.258	105
3	2	4	0.197	163
4	5	6	0.140	100
5	3	6	0.018	76
6	2	3	0.037	102
7	4	5	0.037	105

TABLE II
THERMAL UNIT CHARACTERISTICS

Unit	a ($/MW^{2}h)	b ($/MWh)	c ($/h)	P_{min} (MW)	P_{max} (MW)	SU ($)	SD ($)	Min. on (h)	Min. off (h)
G1	0.099	6.589	211.43	100	320	100	50	4	3
G2	0.203	7.629	217.43	10	160	200	40	3	2
G3	0.494	10.07	102.86	10	100	80	10	1	1

Here, the penalty for load curtailment is 1000 $/MWh, while the penalty for ramping curtailments are calculated as 500 $/MW/h, 875 $/MW/h, 944 $/MW/h, and 968 $/MW/h for 60-min, 30-min, 20-min, and 15-min ramping services, respectively. The following cases were considered:

- Case 1: Single-period ramping services without storage unit
- Case 2: Multiple-period ramping services without storage unit
- Case 3: Multiple-period ramping services with storage unit

In each case, the deterministic solution represents the operation schedule in the base case, which is the most probable scenario rather than the expected values of all scenarios. This is because the expected values may not fully capture the volatility in wind speed/wind generation. That is, taking the expected value of the wind speed as the base case will flatten the hourly wind speed profile, as the weighted mean of all scenarios would certainly have less volatility than the most probable scenario does. This, in turn, would lead to less ramping requirements and possibly cause more flexibility scarcity events in extreme conditions. Similarly, the stochastic solution represents the operation schedule in multiple scenarios with corresponding probabilities.

The mean daily wind speed is 10 m/s, which follows Weibull probability distribution function with Weibull coefficient equal to 2.1. The autocorrelation factor for 5-minute lag is 0.989 considering the 1-hour lag autocorrelation factor as 0.88. The autocorrelation parameter for a lag of k intra-hour time steps is given by $r_k = (r_1)^k$ where r_1 is the hourly correlation factor, $k = 60/t$, and t is the length of the intra-hour time step in minutes. The hour of peak wind speed is 15:00, and the diurnal pattern strength is 0.21. The problem is solved by CPLEX 12.6 on a windows machine with 3.2 GHz Core i5 processor and 8GB memory.

1) Case 1: Single-period ramping services without storage unit

In this case, the single-period ramping capability of the thermal generation units is extended beyond the ER limit to follow the demand fluctuations, while the wind generation is considered as curtailable generation resource in the network.

a) Deterministic solution

The operation cost in this case is $139,424. The units G1 and G2 were committed 24 hours and unit G3 is committed at hours 1-3, 5, 6, 9, 17-20, and 24. In this case, unit G3 is committed at hour 9 to provide RU service at this hour and RD service at hour 10. The operation cost represents the operation cost of the units as well as the cost of the load curtailment. The single-period inelastic ramping costs for G1-G3 are respectively $1,593.5, $212.5, and $0. If the provided ramping service was restricted to ER, the operation cost would increase to $212,195 Thus, $1,806 is paid to the units to compensate for inelastic ramping services and to save $70,965 in operation cost. In order to illustrate the impact of load following services on the operation schedule, the demand profile on bus 3 at hours 5 to 7 is compared to the served demand in Fig. 4. The dispatched wind generation to provide ramping services is compared to the available wind energy at hours 5 to 7 in Fig. 5. The following observations are presented:

- The single-period ramping of the generation units will result in the curtailment in the required ramping of the demand. At hour 7, G2 served the 26.95 MW/h RD requirement of the demand on bus 4, and W1 served 20-min RD requirement of the demand on bus 5 by decreasing the dispatched wind from 42.34 MW to 6.4 MW. The generation units failed to follow the load in this case because of the limitation in providing multiple-period ramping. As shown in Fig. 4, to serve the 107.80 MW/h 15-min RD requirement on bus 3 at hour 7 (DF in Fig. 4), G1 provided 50 MW/h, and G3 provided 40 MW/h elastic and inelastic RD services from 6:45 to 7:00. Thus, 17.80 MW/h of 15-min RD requirement at bus 3 is curtailed at hour 7, which is 0.55 MWh energy curtailment at this hour (DEF in Fig. 4). In this case, G2 is capable of providing (40-26.95=13.05 MW/h) more inelastic RD services, and W1 is capable of providing (6.4-0=6.4 MW/h) RD services, if they were able to provide multiple-period ramping services.
- The limitations imposed by ramping requirement of the demand will limit the hourly dispatch and ramping services provided by generation units and will lead to demand or ramping curtailment in consecutive hours. Here, as G1 and G3 are required to provide large 15-min RD services at hour 7, they fail to follow the demand at hours 6 and 7 as a result of the limitations on their RD services. At hour 7, G1 provides the maximum 50 MW/h RD service and G3 provides 40 MW/h RD service. As the dispatch of G1 at 7:00 is 117.49 MW, the hourly dispatch cannot exceed 129.99 MW at 6:00. Similarly, the dispatch of G3 cannot exceed 10 MW as the unit is de-committed in the next hour imposed by (25). Hence G1 and G3 cannot provide any RU services at hour 6, and the demand curtailed at bus 3 at 6:00-6:45 as a result of limitations on the generation dispatch of G1 and G3, is 3.33 MWh (BCDE in Fig. 4). The generation dispatch of G2 and W1 at 7:00 is 64.46 MW and 42.34 MW, respectively. Here, G2 serves the RD requirement of the demand on bus 5, and W1 serves the RD requirement of the demand on bus 4.

At hour 6, G2 and W1 served the RU requirements of the demand at buses 5 and 4 respectively. As shown in Fig 4, the demand on bus 3 is 71.05 MW at hour 5, and the time span for RU is 30-min to reach 75.37 MW at hour 6. However, the served demand at this hour is 70.92 MW and the provided 60-min RD service is 0.131 MW/h. The provided dispatch at hour 7 limits the hourly dispatch at 6:00 (70.92 MW), which further increases the energy curtailment in 5:30-6:00 to 1.14 MWh (ABC in Fig. 4).

- The wind curtailment provides flexibility to serve the ramping requirements of the demand in the network. In Fig. 5, the areas ABC and CEHD present respectively 0.36 MWh and 7.95 MWh of the curtailed wind generation during hours 6 and 7. The total wind curtailment in this case is 121.33 MWh and the total ramping curtailment is 27.1 MW/h.

Once the wind generation is non-dispatchable, the total demand and ramping curtailments for multiple ramping processes are increased to 42.46 MWh and 187.052 MW/h, respectively and the operation cost is increased to $432,318.636. In this case, the inelastic ramping costs for G1-G3 are respectively increased to $9,532, $5,359, and $122.

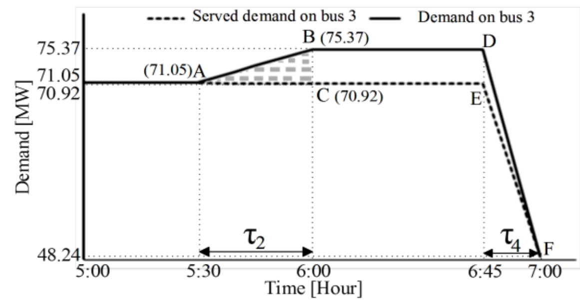

Fig. 4. The demand curve of bus 3 during hours 6 and 7 in Case 1

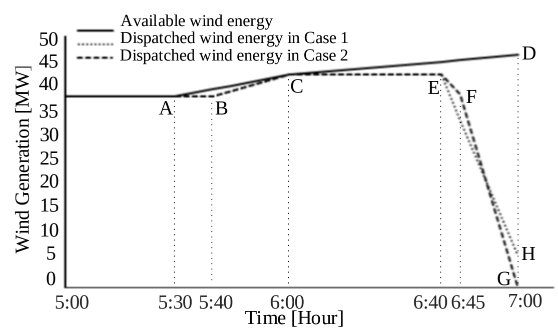

Fig. 5. Available and dispatched wind generation at hours 6 and 7 in Cases 1 and 2

b) Stochastic Solution

In this case, the total expected operation cost is $140,683. Here, G1, G2, G3 are committed for the 24 hours. The expected wind curtailment is 249 MWh, which is more than double of that in the deterministic solution. The expected demand curtailment and the ramping curtailment in this case are 3.223 MWh and 86.568 MW/h, respectively. The expected cost of inelastic ramping for G1-G3 is $1,990, $873, and $181, respectively. As shown in this case, the uncertainties in the operation period increased the expected operation cost, wind curtailment, and ramping costs as well as the commitments of the generation units.

2) Case 2: Multiple-period ramping services without storage unit

In this case, there is no storage facility in the network and the thermal generation units will follow the demand fluctuations by providing multiple-period ramping services.

a) Deterministic solution

The operation cost is $105,714 and G1 and G2 are committed for 24 hours. However, G3 is committed at hours 5, 6, 10, and 17-20. Hence G3 is committed for fewer hours compared to Case 1, as the multiple-period ramping services of the less expensive units serve the ramping requirements of the demand. The inelastic ramping costs for G1-G3 are \$80, \$186, and \$0, respectively. In this case, the multiple-period ramping capability decreased the operation and ramping costs of the system respectively. The ramping costs of G1 and G2 in this case are respectively 95% and 12% lower than those in Case1.

The multiple-period ramping enhances the wind generation dispatchability and the load following capability of the generation units, compared to Case 1. In this case, the ramping curtailments correspond to all ramping times are zero and the wind curtailment is 103.72 MWh which is decreased by 14.5% compared to Case 1. Here, the areas ABC and CEFGD in Figure 5, present respectively 0.36 MWh and 7.90 MWh of the curtailed wind generation at hours 6 and 7.

At hour 6, G1 and W1 provide respectively 0.315 MW/h and 12.645 MW/h of 20-min elastic RU services to serve the 12.96 MW/h RU requirement on bus 4, while G2 and W1 provide 20 MW/h and 0.16 MW/h, 30-min elastic RU service to serve 8.64 MW/h and 11.52 MW/h RU requirement on buses 3 and 5, respectively. Comparing to Case 1, the ramping and dispatch curtailment on bus 3 is reduced from 8.64 MW/h and 4.45 MW to 0 MW/h and 0 MW in Case 2.

At hour 7, the wind energy curtailment provides 107.806 MW/h 15-min RD service to serve the 15-min RD requirement at bus 3. The multiple-period ramping capability allows W1 to provide 46.16 MW/h of 20-min RD capability in addition to 15.64 MW/h, 16 MW/h, and 30 MW/h of elastic 20-min RD services provided by G1, G2, and G3 respectively. The total 20-min RD service serves the 20-min RD requirement of 107.806 MW/h at bus 5. Here, G1 and G2 provide 3.998 MW/h and 18.593 MW/h of inelastic 60-min RD services and G1 provides 4.36 MW/h elastic RD service to serve the RD requirement of demand at bus 4. The multiple-period ramping capability enables W1 to serve the RD requirements of bus 5 by curtailing 46.29 MW at 7:00.

Once the wind generation is non-dispatchable, the operation cost is increased to \$321,405 with 47.73 MWh of demand curtailment, and 124.59 MW/h of ramping curtailment for multiple ramping processes. In this case, the inelastic ramping costs for G1-G3 are respectively increased to \$7,410, \$3,273, and \$479. Thus, thermal units provide larger multiple-period ramping services to follow the ramping requirements of the demand and the non-dispatchable wind energy.

b) Stochastic Solution

In this case, the expected operation cost is \$115,319 and all three unit are committed for 24 hours. The expected wind curtailment is 188.85 MWh, which is 24.1% lower than that in Case 1, and 45.1% higher than that in the deterministic solution. The expected demand curtailment and the ramping curtailment in this case are reduced to 0.139 MWh and 17.89 MW/h respectively compared to Case 1. The expected cost of inelastic ramping for G1-G3 are \$404, \$794, and \$45, respectively, which are decreased by 79.7%, 9.04%, and 75.1%, compared to Case 1.

Fig. 6 shows how the value of the objective function in master problem changes over iterations. It is seen that adding feasibility cuts to the master problem will lead to an increase in the objective value at each iteration. After 43 iterations in the outer loop, the objectives in both sub-problems are zero, suggesting the convergence of the BD. The objectives of the first sub-problem at the first iteration in outer loop is given in Table III. Here, after 4 iterations in inner loop, the objective of the first sub-problem becomes zero, while the objective of the second sub-problem is equal to 2223.57. Once the feasibility cut of the second sub-problem is added to the master problem at the second iteration of outer loop, the objective of the first sub-problem is 2.40. Thus, a feasibility cut is added to the master problem that makes the objective of the first sub-problem equal to zero at the second iteration of inner loop. The objective of the second sub-problem is 1427.83 at this stage, and the associated feasibility cut is added to the master problem. In the third iteration of the outer loop, the objective of first sub-problem in the first iteration of inner loop is 13.02, which becomes zero in the second iteration by adding feasibility cuts to the master problem. At this stage, the objective of the second sub-problem decreases to 936.62 as shown in Fig. 6. Here, the impact of adding feasibility cuts on the value of objective in the master problem is illustrated. By adding the feasibility cuts, the objectives in the first and second sub-problems, which represent the demand/supply mismatches in dispatch and ramping, converge to zero.

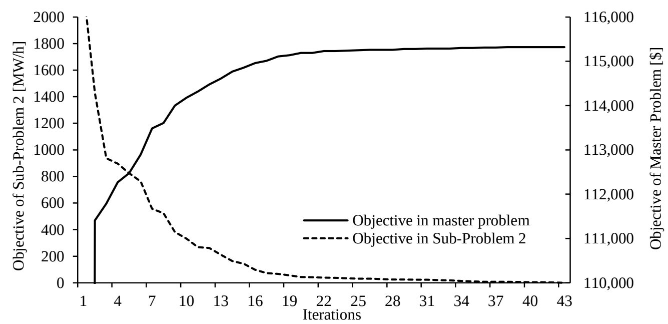

Figure 6. The objective function in master problem (\$) and mismatch in sub-problem 2 (MW/h)

TABLE III
OBJECTIVES IN MASTER PROBLEM AND SUB-PROBLEM 1 IN THE FIRST ITERATION OF OUTER LOOP

Iterations	Sub-problem 1 [MW]	Master problem [\$]
1	5057.25	0
2	8.92	107,790
3	0.184	108,200
4	0	108,280

3) Case 3: Multiple-period ramping services with storage unit

In this case, the energy storage unit is coordinated with the generation facilities and the thermal generation units will provide multiple-period ramping services.

a) Deterministic solution

The operation cost is \$99,429, which is lower compared to Cases 1 and 2. In this case, G1 and G2 are committed for 24

This is the author's version of an article that has been published in this journal. Changes were made to this version by the publisher prior to publication.
The final version of record is available at http://dx.doi.org/10.1109/TSTE.2016.2570218

hours while G3 is committed at hours 4-6, 8, 9, 10-15, 23 and 24. The inelastic ramping costs of G1 and G3 are zero, i.e. G1 and G3 will remain in their ER and the inelastic ramping cost of G2 is $64. The ramping curtailments correspond to all ramping times are zero.

To serve the ramping requirement of the demand at hour 6, the storage unit and W1 provide respectively 11.57 MW/h and 8.59 MW/h of 30-min RU services, while the multiple-period ramping capability enables the storage unit to serve 12.96 MW/h RU requirement of the demand on bus 4 for 20 minutes. To serve RD requirement at hour 7, G1, G2 and storage unit provide respectively 2.73 MW/h, 6.32 MW/h, and 98.75 MW/h 20-min RD services, while the storage unit provides 43.8 MW/h 15-minutes RD services in addition to 64 MW/h 15-min RD service provided by G3 to serve the RD requirement at bus 3.

The state of the storage unit is changed from discharging at hour 6 to charging at hour 7. The storage unit requires 10.59 MW/h of 60-min, 19.36 MW/h of 30-min, and 24 MW/h of 20-min RU service in charging state which are served by 3.95 MW/h of 60-min RU service provided by W1, 24 MW/h of 20-min RU service provided by G1, 0.64 MW/h of 60-min and 19.36 MW/h of 30-min elastic RU service provided by G2, and 6 MW/h of 60-min RU service provided by G3. Here, the multiple-period ramping capability improves the load following services provided by the generation units. For instance, the storage unit withdraws 6 MW/h of 60-min RU provided by G3, so G3 could provide 64 MW/h of 15-min RD service. Once the storage unit does not compensate the RU and multiple-period ramping service of G3; G3 would only provide 40 MW/h of 15-min RD service. The motivation to increase the commitment of G3 in this case is to provide ramping services in such conditions.

The storage unit also withdraws 3.95 MW/h of 60-min RU service provided by the wind generation from 6:00 to 7:00, and the total wind curtailment in this case is zero. Hence coordinating storage facilities and generation units with multiple-period ramping capability enhances the wind generation dispatchability and improves the load following services in the network.

b) Stochastic Solution

In this case, the expected operation cost is $105,223, which is lower than those in Cases 1 and 2. The total expected ramping curtailment is zero. All units are committed for 24 hours except for G3, which is de-committed at hour 7. The expected wind curtailment is 47.65 MWh, which is 80.8% and 74.65% lower than those in Cases 1 and 2, respectively. The expected cost of inelastic ramping for G1-G3 is $52, $167, and $0.593, respectively. In this case, the expected ramping costs are decreased by 97.4%, 80.8%, and 99.6%, respectively compared to Case 1.

C. IEEE 118-bus Power System

In this case, the modified IEEE-118 bus system is used to show the effectiveness of the proposed approach in addressing the multiple-period ramping capabilities of the generation units. The presented network consists of 118 buses, 186 lines, 54 thermal units, and 5 energy storage facilities. There are 5 wind generation units that are installed at buses 8, 30, 38, 49, and 65. The capacity of each wind units is 150 MW. The characteristics of the wind speed profile are given in Table IV. The system peak demand is 3,526 MW. The installed wind generation is 21.2% of the system peak demand. Three cases similar to the presented cases for 6-bus power system are considered in this case study. In table V, the operation cost and wind energy curtailment are given for stochastic and deterministic solutions in Cases 1-3. The wind curtailment in deterministic solution of Cases 2 and 3 are lower than those in Case 1. Similar to the previous case study, the operation cost in deterministic solution in Case 3 is lower than those in Cases 1 and 2, which highlights the merit of multiple-period ramping services and storage facilities to provide load following services. The outcomes in this case are consistent with the results of the previous case (6-bus power system). The operation cost of the deterministic solution in Case 2 is lower than that in Case 1. Here, the operation cost in Case 2 is reduced by 1.01% from that in Case 1. The expected operation cost for stochastic solution in Case 3 is 9.32% lower than that in Case 2. This indicates that the storage unit also contributes to enhancing the economic performance of the modified IEEE 118-bus system by providing multiple-period ramping services. In addition, the wind curtailment is decreased by 98.1% in the stochastic solution of Case 3 compared to that in Case 1. Thus, multiple-period ramping processes and energy storage enhance the dispatchability of the volatile wind generation with uncertainties.

In the MIP-based stochastic solution of Case 2, the total numbers of binary variables, continuous variables, and the constraints are 5142, 849150, and 726579, respectively. However, when using the BD, the total numbers of them in the master problem are 5142, 617500, and 359474, respectively, with 101381 continuous variables and 138841 constraints in the first sub-problem, and 223761 continuous variables and 222721 constraints in the second sub-problem. If there is mismatch in each sub-problem, only 120 constraints will be added to the master problem in the next iteration. Hence, the number of variables and constraints in each solution is smaller when using BD to solve the proposed problem.

The uncertainties in multiple-period ramping processes could be addressed using the interval based or robust optimization techniques [18], [19]. The robust optimization addresses the worst scenarios for ramping requirements including high ramping rates at short ramping times, which requires fast response units with higher ramping costs to follow the net demand pattern. The proposed multiple-period ramping formulation could also be used for IIUC [18]. The interval based optimization technique captures the worst system conditions by limited number of scenarios. In this case, IIUC provide a more conservative solution compared to scenario based stochastic solution. While the process burden for handling the uncertainties are much lower compared to scenario based optimization problem, the simulation outcomes are very much dependent on the determined scenarios.

TABLE IV
WIND SPEED PROFILE AT SITES

	Site 1	Site 2	Site 3	Site 4	Site 5
Weibull Coefficient	1.17	2.03	2.19	2.9	2.26
Auto Correlation Factor	0.761	0.943	0.957	0.88	0.925
Diurnal Wind Pattern	0.11	0.0944	0.0969	0.0196	0.0668
Hour of Peak wind speed	24	14	13	20	22

TABLE V
RESULTS FOR 118-BUS NETWORK

	Case1	Case 2	Case 3
Operation Cost ($)	653,118	646,493	586,385
Wind Curtailment (MWh)	1,590.7	1,417.6	0.0
Exp. Operation Cost ($)	694,241	683,777	619,981
Exp. Wind Curtailment (MWh)	2347	1,639.2	46.5

V. CONCLUSION

In this paper, multiple-period ramping services in the generation units with the elastic and inelastic ramping capabilities are presented. The multiple-period ramping capability along with the integration of energy storage facilities are proposed to serve the ramping requirements imposed by the net demand. An approach based on the Benders decomposition technique is presented to procure the multiple-period ramping services in power systems. It is shown that the multiple-period ramping services of the dispatchable units will increase the dispatchability of the renewable energy resources and reduce the demand curtailment. Moreover, the integration of energy storage facilities decreases the wind curtailment and improves the ramping capability of dispatchable generation units. The elastic and inelastic ramping services of the units are defined with associated ramping costs for inelastic ramping service. The proposed methodology is extended to address the deterministic and stochastic solutions.

REFERENCES

[1] Z. Zhao and L. Wu, "Impacts of High Penetration Wind Generation and Demand Response on LMPs in Day-Ahead Market," *IEEE Trans. Smart Grids*, vol. 5, no. 1, pp. 220-229, Jan. 2014.
[2] Y. V. Makarov, C. Loutan, M. Jian, and P. de Mello, "Operational impacts of wind generation on California power systems," *IEEE Trans. Power Syst.*, vol. 24, no. 2, pp. 1039–1050, May 2009.
[3] H. Wu, M. Shahidehpour, and A. Al-Abdulwahab, "Hourly demand response in day-ahead scheduling for managing the variability of renewable energy," *IET Gen. Transm. Distr.*, vol. 7, no. 3, pp. 226–234, Mar. 2013.
[4] N. Navid and G. Rosenwald, "Market Solutions for Managing Ramp Flexibility With High Penetration of Renewable Resource," *IEEE Trans. Sust. Energy*, vol. 3, no. 4, pp. 784-790, Oct. 2012.
[5] M. E. Khodayar, M. Shahidehpour, and L. Wu, "Enhancing the dispatchability of variable wind generation by coordination with pumped storage hydro units in stochastic power systems," *IEEE Trans. Power Syst.*, vol. 28, no. 3, pp. 2808–2818, Aug. 2013.
[6] H. Wu, M. Shahidehpour, A. Alabdulwahab, and A. Abusorrah, "Thermal generation flexibility with ramping costs and hourly demand response in stochastic security-constrained scheduling of variable energy sources," *IEEE Trans. on Power Syst.*, vol. 30, no. 6, pp. 2955-2964, Nov. 2015.
[7] C. Wang and S. M. Shahidehpour, "Optimal generation scheduling with ramping costs," *IEEE Trans. on Power Syst*., vol. 10, no. 1, pp. 60-67, Feb. 1995.
[8] G.B. Shrestha, S. Kai, and L. Goel, "Strategic self-dispatch considering ramping costs in deregulated power markets," *IEEE Trans. on Power Syst.*, vol. 19, no. 3, pp. 1575-1581, Aug. 2004.
[9] T. Li and M. Shahidehpour, "Dynamic ramping in unit commitment," *IEEE Trans. Power Syst*., vol. 22, no. 3, pp. 1379-1381, Aug. 2007.
[10] H. Wu, M. Shahidehpour, and M. E. Khodayar, "Hourly demand response in day-ahead scheduling considering generating unit ramping cost," *IEEE Trans. Power Syst.*, vol. 28, no. 3, pp. 2446-2454, Apr. 2013.
[11] A. J. Lamadrid, T. Mount, and W. Jeon, "The effect of stochastic wind generation on ramping costs and the system benefits of storage," *System Science (HICSS), 2013 46th Hawaii International Conference on*, pp. 2271-2281, Jan 2013.
[12] N. Troy, D. Flynn, M. Milligan, and M. O'Malley, "Unit commitment with dynamic cycling costs," *IEEE Trans. Power Syst.*, vol. PP, no. 99, p. 1, Nov. 2012.
[13] A. J. Lamadrid and T. Mount, "Ancillary services in systems with high penetrations of renewable energy sources, the case of ramping," *Energy Economics*, vol. 34, no. 6, pp. 1959 – 1971, 2012.
[14] D. Lew, G. Brinkman, E. Ibanez, A. Florita, M. Heaney, B. M. Hodge, G. S. M. Hummon, J. King, S. A. Lefton, N. Kumar, D. Agan, G. Jordan, and S. Venkataraman., "The western wind and solar integration study phase 2," *National Renewable Energy Laboratory*, NREL/TP-5500-55588, 2013.
[15] B T. Haring, D. Kirschen, and G. Andersson, "Efficient allocation of balancing and ramping costs," *in Proc. 18th Power Systems Computation Conf. (PSCC)*, Wroclaw, Poland, Aug. 18–22, 2014.
[16] Y. Dvorkin, M. A. Ortega-Vazquez, and D. S. Kirschen, "Assessing flexibility requirements in power systems," *IET Gener., Transm., Distrib*, vol. 8, no. 11, pp. 1820-1830, Nov. 2014.
[17] H. Nosair and F. Bouffard, "Flexibility envelopes for power system operational planning," *IEEE Trans. Sust. Energy*, vol. 6, no. 3, pp. 800-809, Jul. 2015.
[18] H. Pandžić, Y. Dvorkin, T. Qiu, Y. Wang, and D. S. Kirschen, "Toward cost-efficient and reliable unit commitment under uncertainty," *IEEE Trans. on Power Syst.*, Early Access.
[19] A. A. Thatte, X. A. Sun, and X. Le, "Robust optimization based economic dispatch for managing system ramp requirement," *in Proc. IEEE Hawaii Int. Conf. Syst. Sci.*, Waikoloa, HI, USA, 2014, pp. 2344–2352.
[20] J. Condren, T. W. Gedra and P. Damrongkulkamjorn "Optimal power flow with expected security cost," *IEEE Trans. on Power Syst.*, vol. 21, no. 2, pp. 541-547, May 2006.
[21] C. Wang and S. M. Shahidehpour, "Effects of ramp-process limits on unit commitment and economic-dispatch," *IEEE Trans. on Power Syst*., vol. 8, no. 3, pp. 1341–1350, Aug. 1993.
[22] D. Simopoulos and S. Kavatza, "Consideration of Ramp Process Constraints in Unit Commitment Using Simulated Annealing", *Power Tech, 2005 IEEE Russia*, 27-30 Jun. 2005.
[23] C. Wang and S. M. Shahidehpour, "Ramp-process limits in unit commitment and economic dispatch incorporating rotor fatigue effect," *IEEE Trans. Power Syst*., vol. 9, no. 3, pp. 1539–1545, Aug. 1994.
[24] J. M. Arroyo and A. J. Conejo "Modeling of start-up and shut-downpower trajectories of thermal units" *IEEE Trans. Power Syst.*, vol. 19, no. 3, pp. 1562-1568, 2004.
[25] G. Morales-Espana, A. Ramos, and J. García-González, "An MIP formulation for joint market-clearing of energy and reserves based on ramp scheduling," *IEEE Trans. Power Syst*., vol. 29, no. 1,pp. 476-488, Jan. 2014.
[26] L. Xu, "Flexible ramping products: draft final proposal," *California ISO*, Folsom, CA, 2012. [online]: Available: https://www.caiso.com/Documents/DraftFinalProposal-FlexibleRampingProduct.pdf
[27] B. Wang and B. Hobbs, "Flexiramp market design for real-time operations: Can it approach the stochastic optimization ideal?" *in Proc. IEEE Power Energy Soc. Gen. Meeting*, Vancouver, BC, USA, Jul. 2013, pp. 1–5.
[28] B. Wang and B. Hobbs, "A flexible ramping product: Can it help realtime dispatch markets approach the stochastic dispatch ideal?," *Elect. Power Syst. Res*., vol. 109, Apr. 2014.
[29] A. Street, A. Moreira, and J. Arroyo, "Energy and reserve scheduling under a joint generation and transmission security criterion: An adjustable robust optimization approach," *IEEE Trans. on Power Syst.*, vol. 29, no. 1, pp. 3–14, 2014.
[30] Y. Fu, M. Shahidehpour, and Z. Li, "Security-constrained unit commitment with ac constraints," *IEEE Trans. Power Syst*., vol. 20, no. 2, pp. 1001–1013, May 2005.
[31] J. Wang, M. Shahidehpour, and Z. Li, "Security-constrained unit commitment with volatile wind power generation," *IEEE Trans. Power Syst.*, vol. 23, no. 3, pp. 1319–1327, Aug. 2008.

[32] R. Billinton and R. Allan, Reliability Evaluation of Power Systems, 2nd ed. London, U.K.: Plenum, 1996.
[33] W. H. Greene, Econometric Analysis, 5th ed. Upper Saddle River, NJ: Prentice-Hall, 2003.
[34] J. F. Manwell *et al*., Hybrid2—A hybrid system simulation model theory manual Renewable Energy Research Laboratory, Department of Mechanical Engineering, University of Massachusetts, Jun. 2006.
[35] Z. Song, X. Geng, A. Kusiak, and C. Xu, "Mining Markov chain transition matrix from wind speed time series data," *Expert Systems with Applications*," vol. 38, pp. 10229–10239, 2011.
[36] L. Söder, "Simulation of wind speed forecast errors for operation planning of multiarea power systems," *in Proc. 2004 Int. Conf. Probabilistic Methods Applied to Power Systems*, Sep. 12–16, 2004, pp. 723–728.
[37] A. Boone, "Simulation of short-term wind speed forecast errors using a multi-variate ARMA (1,1) time-series model," Master thesis, KTH, Stockholm, Sweden, 2005.
[38] Nielsen, H.A., and Madsen, H, "Analyse og simulering af prædiktionsfejl for vindenergiproduktion ved indmelding til NordPool," *Informatics and Mathematical Modelling*, Technical University of Denmark, Lyngby, Denmark , 2002
[39] H. A. Nielsen, T. S. Nielsen, and H. Madsen, "On on-line systems for short-term forecasting for energy systems," *Proceedings of the OR 2002 conference*. Klagenfurt, Austria: Springer, 2002, pp. 265-271.
[40] M. Lange, "Analysis of the Uncertainty of Wind Power Predictions," Ph.D. dissertation, Carl von Ossietzky Universitat Oldenburg, 2003.
[41] H. Bludszuweit, J. Dominguez-Navarro, and A. Llombart, "Statistical analysis of wind power forecast error," *IEEE Trans. Power Syst.*, vol. 23, no. 3, pp. 983–991, Aug. 2008.
[42] K. Dietrich, J. M. Latorre, L. Olmos, A. Ramos, and J. P. Ignacio, "Stochastic Unit Commitment Considering Uncertain Wind Production in an Isolated System," *4th Conf. on Energy Econ. and Tech*., Dresden, Germany, 2009, pp. 1–6.
[43] N. Menemenlis, M. Huneault, and A. Robitaille, "Computation of dynamic operating balancing reserve for wind power integration for the time-horizon 1-48 hours," *IEEE Trans. Sustain. Energy*, vol. 3, no. 4, pp. 692–702, Oct. 2012.
[44] B. M. Hodge and M. Milligan, "Wind power forecasting error distributions over multiple timescales," *IEEE PES Gen meeting 2011*, Detroit, Michigan, USA, 2011.
[45] K. Bruninx, E. Delarue, and W. Dhaeseleer, "Statistical description of the error on wind power forecasts via a Levy alpha-stable distribution," *EUI RSCAS Working Paper 2013/50*. EUI Working Papers, 2013, pp. 1–8. [Online]. Available: http://http://cadmus.eui.eu/handle/1814/27520.
[46] K. Bruninx and E. Delarue, "A statistical description of the error on wind power forecasts for probabilistic reserve sizing," *IEEE Trans. Sustain. Energy*, vol. 5, no. 3, pp. 995–1002, Jul. 2014.
[47] J. Dupacová, N. Gröwe-Kuska, and W. Römisch, "Scenario reduction in stochastic programming: An approach using probability metrics," *Math. Program.*, vol. A95, pp. 493–511, 2003.
[48] GAMS/SCENRED Documentation. [Online]. Available: http://www. gams.com/dd/docs/solvers/scenred.pdf.