Risk-Adjusted Unit Commitment for Systems with High Penetration of Renewables

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***Abstract*—This paper presents a framework for scheduling generation in power systems with high penetration of renewable energy resources (RERs). This framework aims to facilitate the participation of RERs in the day-ahead market (DAM). Specifically, it utilizes a risk segmentation technique that breaks bid curves of RERs into tranches with different grades of risk. Assigning a higher price to a tranche with greater risk can prevent an asset owner from incurring losses when the asset owner cannot produce the scheduled amount of energy in DAM and has to buy energy from the real-time market. In the proposed framework the system operator utilizes risk-segmented bids from RERs and reliability constraints to solve a risk-adjusted unit commitment problem. The resulting increased participation of RERs in DAM benefits the asset owners by reducing curtailment and consumers by lowering the DAM energy cost. The approach is validated on a 68-bus system representing the New York grid.**

***Index Terms*—Day-ahead market, renewable energy resources, risk segmentation, tranches, unit commitment.**

I. Introduction

Governments around the world have set targets for reducing carbon dioxide emission due to their power systems (e.g. 100% carbon-free electrical energy has been targeted by 2040 in New York State [1], and by 2050 in Massachusetts [2] and the European Union [3]). If these targets are to be met, power grids would have to significantly increase the penetration of renewable energy resources (RERs). However, the incorporation of a large portfolio of different types of RERs poses several challenges for the power system operator. First, it should be ensured that the inclusion of renewables lowers the cost of electricity for consumers. Second, it should limit the producers' risk exposure due to the variability of renewables. Third, this inclusion should not be at the expense of the power system's reliability. Therefore, there is a need to develop a unit commitment (UC) framework specifically tailored to systems with high penetration of RERs.

Past work in this area has attempted to address the aforementioned challenges in grids with a high penetration of RERs [4]–[7]. In order to account for the stochasticity in the daily output of the RERs, researchers have used stochastic UC (SUC) to determine the generation schedule [8], [9], including risk-constrained SUC [10], [11]. Solving SUC problems may require scenario generation using Monte Carlo simulations, which can significantly increase the computational complexity. Therefore, SUC may not be a feasible approach for scheduling generators in large power systems.

In the proposed approach, the stochastic nature of the output from RERs is embedded in the bid curves submitted by asset (wind or solar farm) owners in the day-ahead market (DAM). The bid curves are divided into segments (tranches), that correspond to different levels of risk associated with not being able to deliver scheduled amount of energy in DAM. The system operator calculates reliability of each tranche based on historic performance and classifies each tranche as either reliable or intermittent. The committed amount of energy from intermittent tranches is included in the reliability constraint which ensures that sufficient reserve is scheduled to not only cover standard N-1 or N-1-1 generation contingency, but also to provide dynamic reserve for the least reliable portion of the committed energy. The advantage of this approach is that it is formulated as a deterministic UC problem, which is faster to compute and requires less changes to existing practices employed by system operators in actual power systems. In addition, marginal reliability and weighted average reliability metrics are proposed to assess the UC solution.

II. Risk-Segmented Tranching

The risk management solution for the RERs uses a risk segmentation technique called tranching, which bundles risk into different grades of risk. Each tranche represents a block of power that carries a certain grade of risk. The design of the risk-segmented tranches is done based on historical generation and forecast data in three sequential stages: analyzing the generation risk profile of the renewable resources, defining the tranches or the identification of cutoffs in the renewable generation, and pricing the tranches.

We propose three tranches with incremental levels of risk: risk-free, mezzanine and equity. For example, the tranches are defined by estimating the cutoffs or attachment and detachment points of the renewable units' generation levels. The cutoffs correspond to the specific percentiles of hourly renewable generation distribution. Each tranche corresponds to a certain level of risk in terms of meeting the contractual commitment

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of delivery at the given time. The tranche attachment and detachment points for a sample wind unit in Western NY are 4%ile to 7%ile for the risk-free tranche, 8%ile to 25%ile for mezzanine tranche, and 26%ile to 60%ile for the equite tranche.

In addition, risk-free tranche has a generation probability exceedance between 96% and 93%; mezzanine tranche has a generation probability exceedance between 92% and 75%; and equity tranche has a generation probability exceedance between 74% and 40%. The risk-free tranche has the same degree of risk as that of a reliable generator, such as a combined-cycle unit, thereby making the UC treat the risk-free tranche of the renewable unit equivalent to the reliable generation from other traditional generators and dispatch tranche. The mezzanine tranche represents the contractual commitments with a higher grade of risk than the risk-free tranche, and the equity tranche represents the contractual commitments with a higher grade of risk than the mezzanine tranche. The hourly percentile power points (MW) generated in each tranche are used to price the risk-segmented tranches.

In the current day-ahead energy markets, the renewable generators are price takers instead of setters. For the renewables to participate in the day-ahead market and compete with the traditional generators, they need to place competitive bids. We utilize a market-based pricing framework developed in [12] to determine the risk-responsive bids for the tranches. The pricing formulation accounts for the risk of generation shortfall associated with the assurance of each bid-point of the tranche. The two elements of the pricing formulation capture, first the probability of successful delivery, and second, the failure to deliver on the commitment of the tranche. The pricing formulation is as follows:

$$\begin{aligned} \boldsymbol{P_x} = \eta * E[D_t|Y_{t+1} > C_x] \ * \ P(Y_{t+1} > C_x) + \\ E^Q[R_{t+1}| \ Y_{t+1} \leq C_x] \ * \ P(Y_{t+1} \leq C_x), \end{aligned} \tag{1}$$

where Y_{t+1} is the generation yield at $t+1$, C_x is the cut-off for a tranche determined by appropriately chosen generation percentile for the x^{th} tranche. η is a discount loading for competitive bids and Q is a risk neutral probability for consistent pricing of day-ahead D_t and real-time R_{t+1} prices.

Fig. 1 shows the renewable bid curve for a wind unit in Western NY for a high generation day. The region with green points represents the risk-free tranche; region with orange points represents the mezzanine tranche; and region with red points represents the equity tranche. The bid curve starts from the attachment point and ranges through the detachment point of the tranches. The pricing formulation gives the bid price ($/MWh) corresponding to each level of bid-point power (MW) generated. The increasing value of the bid price points is reflective of the inherent risk in each incremental level of power generation bid-point.

III. Unit Commitment

In the proposed risk-adjusted UC formulation the RERs submit their bid curves in the form of three tranches: the risk-free tranche, whose probability of not delivering the committed

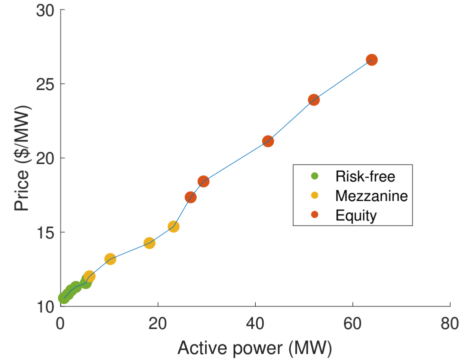


Fig. 1: Risk-free, mezzanine and equity tranches of a NY wind farm.

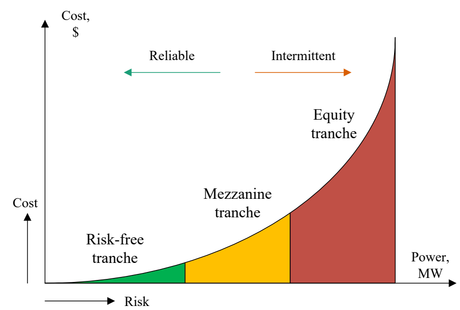


Fig. 2: Risk-free, mezzanine and equity tranches of a RER.

energy is similar to traditional generators; the mezzanine tranche, that has a greater risk of not delivering; and the equity tranche that has the greatest risk associated with it. The tranches can bid small amounts of energy at a low price (risk-free tranche), medium amounts of energy at an average price (mezzanine tranche) and large amounts of energy at a high price (equity tranche). The high bid price compensates the high risk undertaken by the asset owner bidding the equity tranche. A conceptual representation of tranches (drawn not to scale) is shown in Fig. 2. In this formulation each tranche is represented as a separate asset with a separate bid curve and generation constraints such as maximum power.

Thus, besides the traditional input information from the asset owners (such as ramp rates, minimum and maximum power, startup and shutdown cost), the market input provided by each RER includes either 3 bid curves for risk-free, mezzanine, and equity tranche or 1 bid curve and MW values for the boundary between risk-free and mezzanine tranches as well as the boundary between the mezzanine and equity tranches.

A. Asset Classification

To give the system operator flexibility in determining the dynamic reserve component, we propose to perform an asset classification before solving a unit commitment problem. The assets are traditional generators; risk-free, mezzanine and equity tranches of RERs. Thus, each RER is viewed as consisting of three assets. For each asset the system operator calculates reliability for the past 3 months as a ratio of the total produced

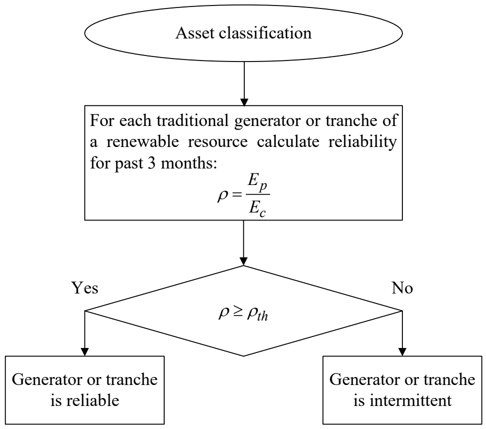


Fig. 3: Asset classification algorithm.

energy based on day-ahead schedule to the total scheduled energy in day-ahead market:

$$\rho = \frac{E_p}{E_c}, \tag{2}$$

where E_p is the total produced energy based on the DAM schedule in past 3 months, and E_c is the total committed energy in DAM for past 3 months. If an asset produced more energy than scheduled, the energy over the scheduled value is not included in E_p. For example, if an asset's equity tranche bid of 50 MW was scheduled in DAM but it produced 100 MW, only the scheduled 50 MW would be counted in E_p calculation.

If the asset reliability is larger or equal to the reliability threshold, then the asset is considered reliable; otherwise, the asset is considered intermittent, and its committed energy has to be covered by reserve. The algorithm of the classification is shown in Fig. 3. A larger value of the threshold corresponds to a more conservative unit commitment solution when more assets are classified as intermittent and have to be covered by reserve.

B. UC Formulation

With all inputs from the asset owners and the sets of reliable and intermittent assets the system operator solves the risk-adjusted unit commitment problem described below:

$$\min_{u_l(\cdot),\forall t,l} \sum_{t\in\mathcal{T}} \Big(\sum_{l\in\mathcal{L}} \big(c_l^p(t) + C_l^R u_l(t) + c_l^{SU}(t) + c_l^{SD}(t) +$$

$$C_R r_l(t) \big) + \sum_{i\in\mathcal{I}} c_i^p(t) + \sum_{n\in\mathcal{N}} C_{LP}[s_n^+ + s_n^-(t)] + C_{RP} s_R(t) \Big) \tag{3}$$

subject to

$$(\mathrm{C}_1)\ \sum_{l\in\mathcal{L}} p_l(t) + \sum_{i\in\mathcal{I}} p_i(t) + \sum_{k\in\delta^+(n)} f_k(t) - \sum_{k\in\delta^-(n)} f_k(t)$$

$$+ s_n(t) = D_n(t) \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T}, \tag{4}$$

$$(\mathrm{C}_2)\ \sum_{l\in\mathcal{L}} r_l(t) + s_R(t) \geq R(t) + \sum_{i\in\mathcal{I}} p_i(t), \quad \forall t \in \mathcal{T}, \tag{5}$$

where $\mathcal{L}$, $\mathcal{I}$, $\mathcal{N}$ and $\mathcal{T}$ are the sets of reliable assets (which includes reliable traditional generators and reliable tranches), intermittent assets, buses, and discrete time steps, respectively, with indices l, i, n and t. We take $c_l^p(t)$ to denote the hourly dollar cost of generating power above the minimum generation output of generator l, $\underline{P}_l$. Let C_l^R be the hourly cost of operating generator l at $\underline{P}_l$. The start-up and shut-down cost of generator l at time t are given by $c_l^{SU}(t)$ and $c_l^{SD}(t)$, respectively. We take C_R and $r_l(t)$ to be the reserve cost and the spinning reserves provided by generator l at time t, respectively. The cost of generating power above $\underline{P}_i$ for intermittent generators is denoted by $c_i^p(t)$. The notation C_{LP} is the penalty cost in \$/MWh for failing to meet or exceeding the load. We take $s_n^+(t)$ and $s_n^-(t)$ to be the positive and negative parts of the slack at bus n at time t, respectively. C_{RP} is the penalty cost in \$/MWh for failing to meet the reserve requirement and $s_R(t)$ is the reserve shortfall at time t in MW. The symbols $p_l(t)$ and $p_i(t)$ denote the power generated by reliable and intermittent generators above $\underline{P}_l$ and $\underline{P}_i$, respectively. $f_k(t)$ is the instantaneous power flow along branch k, and $\delta^+(n)$ and $\delta^-(n)$ are the sets of branches to and from bus n, respectively. Finally, $D_n(t)$ and $R(t)$ are the instantaneous demand at bus n and the instantaneous, system-wide spinning reserve requirement in MW, respectively. For brevity the rest of constraints are not shown. The reader is directed to the "tight" formulation in [13] for an exhaustive list of operational constraints for the UC objective function (3), including up-time/down-time, generation limits, and ramp-up/ramp-down, and networks constraints.

The objective function minimizes the total cost, which consists of the cost of producing energy from reliable and intermittent assets as well as the cost of reserve. In the reserve constraint (5) the sum of the scheduled reserve should be greater or equal to the sum of the reserve requirement determined by the loss of one or two largest units $R(t)$ and the total committed energy from intermittent assets (this term represents only a portion of committed energy from RERs because equity and sometimes mezzanine tranche will be considered intermittent). The second term represents a dynamic reserve component that changes from hour to hour. The size of the component depends on the reliability threshold value determining which tranches are being considered intermittent, and on the amount of energy committed from intermittent assets determined by the bid curves, which are based on the probabilistic forecast. Thus, the stochasticity of RERs is embedded in the bid curves of tranches. The system operator uses the UC/ED solution to send the individual commitment and reserve schedule to asset owners. A potential limitation of the approach is that a system operator may only use portions of the tranches for inclusion in system dispatch.

IV. Reliability Metrics

In the proposed formulation each hour of the UC solution will be evaluated based on the marginal reliability metric and by weighted average reliability metric.

TABLE I: Cumulative available capacity

Generator type	Nuclear	CC	Risk-free tranche	Hydro	GT	Thermal	Mezzanine tranche	Equity tranche
Capacity (GW)	11	14	1	7	5	6	3	4
Cumulative capacity (GW)	11	25	26	33	38	44	47	51
Reliability (%)	98.2	96.1	96	94.9	93.4	91.3	70	30

A. *Marginal Reliability Metric*

The algorithm for the marginal reliability metric calculation is explained below through an example which uses aggregated values corresponding to specific resource type. Given maximum available capacity of committed generation, the energy resources are sorted in descending order of their reliability and the cumulative available capacity is calculated, as shown in Table I. If the cumulative available capacity becomes equal to or greater than the total demand requirement, the reliability value is recorded. This is the marginal reliability metric value for the corresponding hour. In the example provided here, for a demand of 30 GW, the reliability value will be 94.9% and the hydro energy resource will be the resource with marginal reliability for this hour.

B. *Weighted Average Reliability Metric*

The weighted average reliability is defined as average reliability of the reliable scheduled assets weighted by their maximum available capacity as

$$\rho^{wa} = \frac{\Sigma_{k=1}^{n} \rho_k \bar{p}_k}{\Sigma_{k=1}^{n} \bar{p}_k}, \tag{6}$$

where $\bar{p}_k$ is the available capacity of committed asset k, and n is the number of most reliable assets that cover demand. The list of reliable scheduled assets is determined in a manner similar to that for the marginal reliability metric. Using the example from previous subsection, for a demand of 30 GW, the weighted average reliability is 96.5%, whereas for a demand of 40 GW, the weighted average reliability is 95.5%. Both the marginal reliability and weighted average reliability metrics do not directly represent the reliability of the power system as a whole. Instead, these metrics are indicators of the reliability of the assets scheduled for energy and reserve and will always be larger than reliability threshold used to classify the assets.

V. Case Study

The proposed UC framework is tested on a 68-bus system representing the New York grid [14], as shown in Fig. 4. The system has 22 generators operating on various fuel types. The installed capacity and generator types reflect the state of the actual NYISO system in 2020. As the 68-bus system is a highly aggregated system only the following generator types are used: hydro, steam (nuclear), steam (coal), steam (gas), gas turbine (GT), combined cycle (CC), wind, photovoltaic. Bid curves for each generator are scaled from the actual bid curves submitted to NYISO DAM in 2020. The 24-hour load profile represents the day with peak electric energy consumption in 2019. Two scenarios are simulated. In the risk-adjusted scenario, wind farms bid three tranches: risk-free, mezzanine, and equity. The reliability threshold for both scenarios is set to 90%. In the baseline scenario the wind farms bid a small portion of forecast output in DAM (which is equivalent to the risk-free tranche detachment point of the risk-adjusted scenario) at zero price.

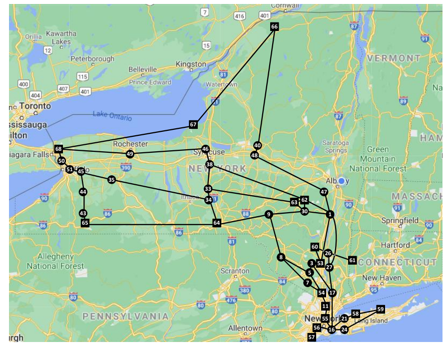


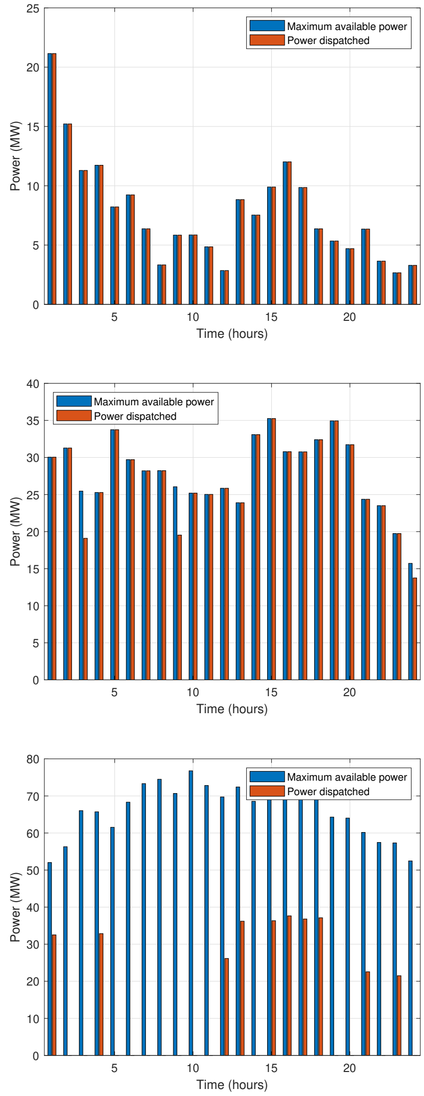
Fig. 4: New York 68-bus system.

In this work, we have used Electrical Grid Research and Engineering Tools (EGRET), a Python-based package for electrical grid optimization [15], to obtain the solution for the risk-adjusted UC for the 68-bus system over a 24-hour period. In addition to the hourly dispatch of tranched assets, we present the evolution of the marginal and weighted average reliability metrics over time for the system.

Fig. 5 shows the maximum power available and the dispatch for each hour of the day for each of the three tranches of one of the wind generators in the 68-bus system. The bid-curves for the three tranches are scaled versions of the one shown in Fig. 1. The risk-free tranche involves bidding small amount of power that can be supplied with a high degree of certainty at a low price, whereas the equity tranche involves bidding a larger amount of power that can supplied with less certainty (and hence incur high risk) at a high price. Therefore, it may be seen in Fig. 5a that the maximum available power for the risk-free tranche is dispatched for all hours of the day. The mezzanine tranche, which represents the case where power is to be supplied at a risk level higher than that of the risk-free tranche for a greater price, is dispatched to a slightly lesser degree than the risk-free tranche, as seen in Fig. 5b. Finally, for the demand scenario considered here, the equity tranche, with its greatest risk level and highest energy price, is dispatched partially for only 10 hours during the day (Fig. 5c).

Table II shows the cost obtained from the UC formulation for the baseline and risk-adjusted cases. It may be seen that for the specific demand scenario for the 68-bus system considered here, introducing tranching for RERs can result in cost savings of approximately 5.34% compared to the baseline. For future work a sensitivity case study comparing different scenarios of bidding in the base case formulation with the proposed formulation will be performed.

Fig. 6 plots the marginal and weighted average reliability



(c)

Fig. 5: Hourly maximum power available and hourly dispatch for one of the wind warms for (a): risk-free, (b): mezzanine and (c): equity tranches.

TABLE II: Total UC solution cost for the baseline and the risk-adjusted cases.

Case	Cost of energy production, $
Baseline	6117034.5
Risk-adjusted	5790052.7

metrics during the day. It may be seen here that up till hour 12, the reliability is higher as hydro units are dispatched. Between hours 13 and 20, as the grid faces an increased demand, the reliability reduces as thermal generators need to be dispatched to meet the increased demand. As the demand subsequently falls, thermal generators are no longer dispatched, causing the reliability metric to revert to its previous level.

VI. Conclusion

The proposed risk-adjusted UC formulation increases the participation of RERs in DAM and reduces the total cost of energy production. As it is a deterministic formulation it can be readily adopted by power system operators.

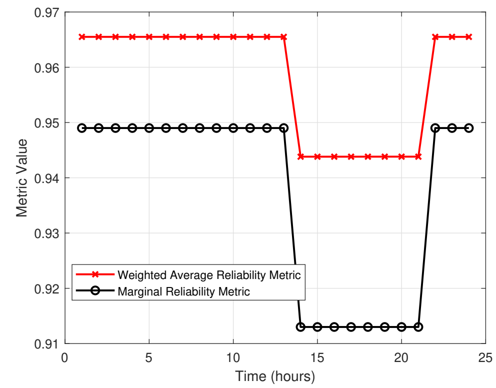


Fig. 6: The two reliability metrics plotted over a 24-hour period.

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