Analysis of Electricity Markets with Risk-adjusted Bidding by Renewable Generators

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***Abstract*—Renewable power generators typically participate as price-takers in current electricity markets, and market clearing prices are determined by cost curves of conventional generators while treating renewable generation as negative load. In this paper, we analyze a new design of electricity markets where renewable power generators are able to bid their *risk-adjusted* cost curves into the market, just like the cost curves of conventional generators. We formally define the new market model, and mathematically show how the renewable cost curves should be determined for the new market to be equivalent to the current market in terms of overall system cost. We further establish that on the average, the total revenue of both conventional and renewable generators, as well as the total cost to consumers, under the proposed market is the same as the current practice. While equivalent in terms of aggregate cost and revenue measures, the new market design allows renewables to be direct participants in the bidding process and bid according to their risk-return tolerance. We demonstrate our analytical results numerically using data obtained from the the Texas grid.**

I. Introduction

Investment into renewable energy assets has been growing exponentially in recent years. Government subsidies on renewable energy generators and other equipment aimed at aiding energy transitioning are also providing strong incentives in this direction. In the United States, state-wide policy initiatives in New York have aimed to deliver 70% of its energy from renewable energy resources by 2030 and 100% emissions-free electricity supply by 2040 [1], utilizing 3 GW of energy storage and 9 GW of offshore wind power.

Despite this surge in renewable energy penetration, the majority of renewable generators today act as *price-takers* in the electricity market, that is, they are either not allowed or unwilling to bid into the market like conventional generators. This appears justifiable on first thought, since: (a) the operating cost curves for renewable generation are nearly zero, unlike conventional generators who have to pay for fuel and bid their generation cost curves into the market; (b) renewable generation is associated with a high degree of uncertainty, making it difficult to provide guaranteed day-ahead commitment like conventional generators. Renewable generators, therefore, mostly supply energy in real-time, and are paid at market clearing prices that are determined from the cost curve bids of the conventional generators. In running the unit commitment and economic dispatch problems for the day ahead market (DAM) and the real-time market (RTM), the system operator can treat the renewables as "negative load".

Since the renewable production is stochastic and not fully predictable, stochastic variants of the unit commitment problem need to be considered. This has led to a vast amount of work on stochastic unit commitment problems [2], [3], [4], which attempt to pose and solve this problem through multi-stage stochastic optimization, chance-constrained programming, robust optimization, stochastic dynamic programming, and other related approaches. Recent works such as [5], [6], [7], [8], [9] either directly assume renewables to be price-takers, or that renewables will be bidding their actual cost (which is close to zero) effectively implying the same. Such a market structure implies that even as renewable supply increases to meet a bulk of the energy demand, market prices are going to be determined by a few conventional generators which can provide nearly risk-free energy commitments. This is undesirable from an economic perspective however, as it does not incentivize renewables to innovate, or reduce their supply variability (which is a root cause behind their inability to bid into the market) – by investing in storage. Wind generators are also increasingly investing in co-located storage [10], which could allow them to commit more reliably to an energy supply, much like conventional generators. Further, as envisioned in our recent work [11], a renewable generator can segment its supply and offer a fraction of its forecast supply as a highly reliable contract, comparable to that of conventional generators. Without a mechanism to bid into the market while adjusting for risk, such technological innovations would not happen, and much of the long-term benefits of high renewable penetration will be forfeited.

With this motivation, this paper aims to analyze a market in which renewable generators can bid into the market, just like conventional generators. We derive expressions for the *risk-adjusted* cost curves of the renewables so that the expected system cost is minimized. Through theoretical analysis, we establish that the performance of the new market (with renewables as bidders) is similar to an existing market (with renewables as price-takers), in terms of key performance metrics that relate to the overall system as well as the individual market players. Specifically, we show that the expected profit earned by both conventional and renewable generators and the cost-to-loads are similar between the two markets. Finally, we present a numerical study of the new market in terms of the above metrics using Texas load and generation data, accounting for forecast errors in renewable generation rates.

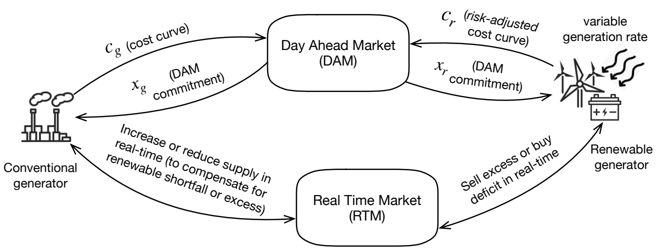

Figure 1: High-level overview of the market with both conventional and renewable bidders.

This paper is structured as follows. Section II describes the system model and the simplifying assumptions made toward analytical tractability. Section III computes analytical expressions for the renewable cost curves and payments made to both conventional and renewable generators on market clearing. Section IV utilizes those expressions to establish the equivalence of the proposed market with current practice in terms of expected social utility, generator profit and load cost. Section V provides results of our numerical study on the Texas grid. Section VI concludes by listing future research directions.

II. System Model

This section provides a description of the system model, including the underlying assumptions, which will be used to define the new market with renewable bidders and compare it with the current practice. We make several simplifying assumptions and approximations on practical electricity market operations to keep our analysis tractable.

We consider the unit commitment (UC) problem in an electricity market for an entire day, solved at an hourly time granularity. We ignore factors that couple the UC problems across different hours, such as ramping constraints of conventional generators and storage capacities that may be associated with renewable generators. This allows us to treat the UC problem in each hour separately from the others. As in traditional electricity markets, we assume that UC happens in two time stages: day-ahead and real-time. However, in the market we analyze, we assume renewable generators bid (risk-adjusted) cost curves, just like conventional generators. Thus, in the first stage, which corresponds to the day-ahead market (DAM) clearing, based on the estimated demand for any given hour and the bid (cost) curves submitted by the conventional and renewable generators, the generators are committed to provide a certain amount of electricity in that hour. In the second stage, which corresponds to real-time market (RTM) clearing, the actual renewable energy supply is realized, and renewable generators who have less supply than committed must make up by buying the shortfall from the RTM. This shortfall must be obtained from other renewables with excess supply, or conventionals which sell additional supply in the RTM to meet this real-time deficit. We assume that renewable energy is not curtailed; therefore, if there is an excess of supply across all renewables, the conventionals reduce their supply in the RTM. We also assume marginal cost pricing, i.e., market participants have to buy or sell energy at the marginal cost of power production, as determined by the submitted cost curves of the generators at the market clearing point.

Fig. 1 provides an illustration of the day-ahead and real-time market operations that we analyze, assuming a single renewable generator unit. More specifically, for the hour under consideration, we make the following assumptions.

1) The demand, denoted by d, is known (or perfectly forecasted) in day-ahead and is strictly greater than the maximum possible power available from the renewable generators.
2) The cost of conventional generators is aggregated into a single cost function, $c_g(x_g)$, which is monotonically increasing and convex in x_g. However, the cost curves of the renewable generators ($c_r(x_r)$ for renewable r) must be considered individually and will be analytically derived in Section III.
3) Renewable power generation realized in real-time is modeled using scenarios $\xi^s \in \Xi$. In each scenario ξ^s, the *total* renewable energy produced is known (or well estimated) by the market operator (ISO).
4) The set of conventional generators is willing to reduce their production to accommodate excess generation by renewable generators. In addition, the conventional generators can increase generation to cover any shortfall in renewable generation.
5) If a renewable r's real-time generation, $\lambda_r(\xi^s)$, differs from its DAM commitment, x_r, then it can either purchase or sell energy in RTM at the prevailing market price, ensuring that its DAM commitment is met and none of its produced power is curtailed.

Note that Assumption 2 follows from the convexity and monotonicity of the cost curve of each conventional generator. Assumption 4 implies full liquidity of the conventional generator, which ensures that all renewable power produced is fully utilized (i.e., not curtailed). Under these assumptions, the ISO can solve an optimization problem to find the allocations of the conventional and the renewable generators in DAM. Depending on the particular scenario ξ^s arising, the generators can trade amongst themselves in the RTM at the market price. The RTM price is determined by the total renewable production realized in real-time, and the cost curve of the conventional generators.

III. Analytical Expressions

In this section, we derive analytical expressions of the risk-adjusted cost curves of each renewable generator, the market clearing payments and profits of each type of generator in both DAM and RTM.

A. Calculating a Cost Curve for Each Renewable

To submit a bid curve, a renewable generator calculates its expected cost function for each accepted bid value. Let R denote the set of renewable generators and x_g denote the power generated by the aggregated conventional generators, with corresponding cost curve $c_g(x_g)$ with derivative $c_g'(x_g)$.

For each scenario ξ^s, let the total renewable output be denoted by

$$\lambda^{TOT}(\xi^s) \,=\, \sum_{r\in R} \lambda_r(\xi^s).$$

Under Assumptions 1 and 4, conventional production x_g in the RTM for scenario s satisfies

$$x_g^{RTM} \,+\, \lambda^{TOT}(\xi^s) \,=\, d. \tag{1}$$

For a given scenario ξ^s and a given renewable generator r with accepted DAM bid of x_r^{DAM}, exploiting Assumptions 4 and 5, the RTM cost for r is:

$$c_r\big(x_r^{DAM}, \xi^s\big) \,=\, c_g'\big(d - \lambda^{TOT}(\xi^s)\big)\,\big(x_r^{DAM} - \lambda_r(\xi^s)\big). \tag{2}$$

Then the expected RTM cost for the renewable r is

$$\begin{aligned} c_r(x_r^{DAM}) \quad &= \mathbb{E}_\Xi\left[c_g'(d - \lambda^{TOT}(\xi^s))\,(x_r^{DAM} - \lambda_r(\xi^s))\right] \\ &=: \alpha x_r^{DAM} \,-\, \beta_r, \end{aligned} \tag{3}$$

$$\begin{aligned} \text{where} \quad \alpha \,:=\, &\mathbb{E}_\Xi\left[c_g'(d - \lambda^{TOT}(\xi^s))\right] \\ &\text{is independent of } r \in R, \end{aligned} \tag{4}$$

$$\beta_r \,:=\, \mathbb{E}_\Xi\left[c_g'(d - \lambda^{TOT}(\xi^s))\,\lambda_r(\xi^s)\right] \;\forall r \in R. \tag{5}$$

Note from Assumption 3 that the ISO knows the value of α and if $x_r^{DAM} < \beta_r/\alpha$, then $c_r(x_r^{DAM}) < 0$. This indicates that renewable r expects to make a profit in the real time market if the accepted bid x_r^{DAM} is sufficiently small. Note also that this curve is valid for $0 \le x_r^{DAM} \le \max_{\xi^s\in\Xi} \lambda_r(\xi^s)$ for each $r \in R$. Calculation of α and β_r using realistic data from the Texas grid is illustrated in Appendix A of [12].

B. Solving the ISO problem with these cost curves

Given the cost curves, the ISO solves the DAM problem:

$$\begin{aligned} &\min_{x_g^{DAM},\{x_r^{DAM}\}} \; c_g(x_g^{DAM}) + \sum_{r\in R} c_r(x_r^{DAM}) \\ &\text{subject to} \quad x_g^{DAM} + \sum_{r\in R} x_r^{DAM} = d \\ &x_g^{DAM} \ge 0, \quad 0 \le x_r^{DAM} \le \max_{\xi^s\in\Xi} \lambda_r(\xi^s),\, \forall r \in R. \end{aligned} \tag{6}$$

Substituting for $c_r(x_r^{DAM})$ from (3) and then using the first constraint to eliminate $\sum_{r\in R} x_r^{DAM}$ gives a convex problem in the single variable x_g^{DAM}. Once the ISO has solved this problem, it can then choose any assignment $\{x_r^{DAM} : r \in R\}$ satisfying (6). We let $U^R = \max_{\xi^s\in\Xi} \sum_{r\in R} \lambda_r(\xi^s)$ denote the maximum possible production from the renewables. Hence the set of solutions x_g^{DAM} to (6) is

$$\{x_g^{DAM*}\} \,=\, \{t \in [d - U^R, d] : c_g'(t) = \alpha\}. \tag{7}$$

C. Who gets paid when?

All the RTM payments are made at the marginal price $c_g'(d - \lambda^{TOT}(\xi^s))$, accounting for adjustments to production schedules due to the realization of a particular scenario ξ^s.

The DAM payments would use the marginal price in the solution of (6), namely α. Thus, we would have payments of

- αx_g^{DAM*} to the conventional generators.
- αx_r^{DAM*} to each renewable generator, where x_r^{DAM*} is the optimal solution chosen by the ISO.

Thus, each generator's DAM payment would be equal to the product of its assigned production value and its marginal cost. The total payout by the ISO would be αd, all in the DAM.

With this payout, the expected DAM+RTM profit for each renewable generator would be

$$\text{profit}_r \,=\, \alpha x_r^{DAM*} \,-\, (\alpha x_r^{DAM*} - \beta_r) \,=\, \beta_r.$$

In scenario ξ^s, the conventional generators would produce $d - \lambda^{TOT}(\xi^s)$, so the net profit for the conventional generators would be

$$\begin{aligned} \text{profit}_g(\xi^s) &= \alpha x_g^{DAM*} \,-\, c_g(d - \lambda^{TOT}(\xi^s)) \\ &+ c_g'(d - \lambda^{TOT}(\xi^s))(d - x_g^{DAM*} - \lambda^{TOT}(\xi^s)), \end{aligned} \tag{8}$$

where the last term is the net revenue received from the renewable generators in the RTM. (The net revenue received in RTM is negative if there is a renewable surplus with $\lambda^{TOT}(\xi^s) > d - x_g^{DAM*}$.)

If the conventional generators were to produce exactly x_g^{DAM*} in the RTM, their profit would be

$$\text{profit}_g^{DAM} \,=\, \alpha x_g^{DAM*} \,-\, c_g(x_g^{DAM*}) \tag{9}$$

The following lemma (proof in Appendix B of [12]) shows that the profit of the conventional generator increases if it adjusts its production so all generated renewable energy is consumed.

Lemma III.1. *Assume we have a scenario with renewable shortfall or surplus, so $\lambda^{TOT}(\xi^s) \neq d - x_g^{DAM*}$. Then the conventional generators make a greater profit by producing $d - \lambda^{TOT}(\xi^s)$ in the RTM than by producing x_g^{DAM*}.*

The proof of the lemma exploits the convexity of $c_g(x_g^{DAM})$, in particular the subgradient inequality.

IV. Markets Equivalence

In this section, using the analytical expressions derived in Section III for the market with renewable bidders, we establish its equivalence with a baseline model where renewables are only price takers. In the baseline, renewable energy sources do not bid in the DAM; instead, they supply energy in real time without incurring any direct costs and are compensated based on the marginal cost of generation determined by conventional generators. Conventional generators submit their cost curves into the DAM, and the ISO clears the market by minimizing the total system cost, ensuring that the scheduled conventional generation, combined with the expected renewable supply $\mu \,=\, \mathbb{E}_\Xi(\lambda^{TOT}(\xi^s))$, adequately meets the demand. This baseline market clearing formulation is similar to the two-stage stochastic unit commitment problem considered in the literature [3], [4]. The next few subsections compare this baseline with the proposed market with renewables bidding cost curves as defined in Section III-A, in terms of profit and revenue of both conventional and renewable generators, and cost to load.

A. Profit and Revenue

We make the following assumption for the rest of this paper.

Assumption 6: Assume the aggregated cost function of the conventional generators is quadratic, i.e., $c_g(x_g) = ax_g^2 + bx_g + c$ with a, b, and c being some constant parameters.

As a consequence of Assumption 6, the gradient $c_g'(x_g^{DAM})$ is a linear function of x_g^{DAM}. Consequently, $\mathbb{E}(c_g'(d - \lambda^{TOT})) = c_g'(d - \mathbb{E}(\lambda^{TOT})) = c_g'(d - \mu)$. In the baseline model, $x_g^{DAM} = d - \mu$, so this x_g satisfies the optimality condition (7) for the proposed model, giving the following proposition (proof in Appendix C of [12]).

Proposition IV.1. *The optimal x_g^{DAM} in the proposed model* (6) *is the same as the optimal x_g^{DAM} in the baseline model.*

Both the baseline and proposed models allow for surplus renewable generation, with the conventional generators backing off as necessary. Hence the optimal choices for x_g in the real-time market are also identical.

Since the DAM and RTM values of the optimal x_g are identical, and since the payments to the conventional generators are determined by the marginal costs c_g', the profits of the conventional generators in any scenario are the same in the proposed and baseline models.

We now analyze the corresponding total profits, i.e., profit $=$ profit^{DAM} $+$ profit^{RTM} for the renewable generators in each market. In both markets, we categorize all situations into two scenarios as follows.

B. Scenario 1: Total Shortfall in RTM ($d > x_g^{DAM^*} + \lambda^{TOT}$)

Profit for the renewable generators in the baseline market, where all their revenue comes from the RTM:

$$\text{profit}_{r^{TOT}}^{\text{baseline}}(\xi_1) = c_g'(d - \lambda^{TOT}(\xi_1))\lambda^{TOT}(\xi_1).$$

In the proposed new market, the renewable generators receive revenue from bidding in the DAM market, with an adjustment from the RTM:

$$\begin{aligned}
&\text{profit}_{r^{TOT}}^{\text{proposed}}(\xi_1) \\
&\quad= \alpha x_{r^{TOT}}^{DAM^*} \\
&\qquad - c_g'(d - \lambda^{TOT}(\xi_1))(d - x_g^{DAM^*} - \lambda^{TOT}(\xi_1)) \\
&\quad= \text{profit}_{r^{TOT}}^{\text{baseline}}(\xi_1) \\
&\qquad - (c_g'(d - \lambda^{TOT}(\xi_1)) - \alpha)x_{r^{TOT}}^{DAM^*}.
\end{aligned}$$

C. Scenario 2: Total Equilibrium/Excess in RTM with no curtailment in renewable generators ($d \leq x_g^{DAM^*} + \lambda^{TOT}$)

For the renewable generators in the baseline market:

$$\text{profit}_{r^{TOT}}^{\text{baseline}}(\xi_2) = c_g'(d - \lambda^{TOT}(\xi_2))\lambda^{TOT}(\xi_2).$$

In the proposed new market:

$$\begin{aligned}
&\text{profit}_{r^{TOT}}^{\text{proposed}}(\xi_2) \\
&\quad= \alpha x_{r^{TOT}}^{DAM^*} \\
&\qquad + c_g'(d - \lambda^{TOT}(\xi_2))(x_g^{DAM^*} + \lambda^{TOT}(\xi_2) - d) \\
&\quad= \text{profit}_{r^{TOT}}^{\text{baseline}}(\xi_1) \\
&\qquad + (\alpha - c_g'(d - \lambda^{TOT}(\xi_2)))x_{r^{TOT}}^{DAM^*}.
\end{aligned}$$

D. Total Expected Profit of Aggregate Renewable Generators with Quadratic Cost Curves

In any scenario ξ, we have

$$\begin{aligned}
&\text{profit}_{r^{TOT}}^{\text{proposed}}(\xi) - \text{profit}_{r^{TOT}}^{\text{baseline}}(\xi) \\
&\quad= -(c_g'(d - \lambda^{TOT}(\xi)) - \alpha)x_{r^{TOT}}^{DAM^*}.
\end{aligned}$$

Using (4), the expected difference in profit between the two models is $\mathbb{E}(c_g'(d - \lambda^{TOT}(\xi)) - \alpha)x_{r^{TOT}}^{DAM^*}) = 0$.

E. Cost to Load Analysis

We define cost to load to be the summation of the profit of the conventional generators, the profit of the renewable generators and the cost for the conventional generators to produce their energy. This is what ISO pays in total under a particular scenario. We obtain:

- With the proposed model, cost to load is always $\alpha(x_g^{DAM^*} + x_{r^{TOT}}^{DAM^*}) = \alpha d$;
- For ξ in scenarios 1 and 2, baseline cost to load is

$$\begin{aligned}
&\text{profit}_g^{\text{baseline}}(\xi) + c_g(d - \lambda^{TOT}(\xi)) + \text{profit}_{r^{TOT}}^{\text{baseline}}(\xi) \\
&\quad= \alpha x_g^{DAM^*} + c_g'(d - \lambda^{TOT}(\xi))(d - x_g^{DAM^*}).
\end{aligned}$$

In Scenario 1, the baseline cost to load is greater than the proposed cost to load because of the strict convexity of the cost function of the conventional generators. In Scenario 2, the baseline cost to load is less than or equal to the proposed cost to load for the same reason.

F. Total Expected Cost to Load with Quadratic Cost Function

We use the same assumptions as in the analysis of the total expected profit under the same probability distribution. Here, we denote cost to load as CTL $=$ profit$_g$ $+$ profit$_{r^{TOT}}$ $+$ GenCost$_g$. In the proposed model the cost to load is always αd, all from the DAM. For each scenario ξ (1 or 2), exploiting (4), we have:

$$\begin{aligned}
&\mathbb{E}[\text{CTL}^{\text{baseline}}(\xi)] \\
&\quad= \mathbb{E}[\alpha x_g^{DAM^*} + c_g'(d - \lambda^{TOT}(\xi))(d - x_g^{DAM^*})] \\
&\quad= \mathbb{E}[c_g'(d - \lambda^{TOT}(\xi))d] \\
&\quad= \mathbb{E}[\text{CTL}^{\text{proposed}}(\xi)].
\end{aligned}$$

V. Evaluation

In our computational analysis, we used MATLAB to simulate market outcomes utilizing the *Hourly Aggregated Wind and Solar Output* dataset in 2024 from the Electric Reliability Council of Texas (ERCOT) [13]. We merged the wind and solar sheets and filtered only weekday data for July. For each hour h, we split these filtered data into training and testing subsets. We then picked the first 10 even-indexed weekdays as the training dataset and the first 10 odd-indexed weekdays as the testing dataset. Note that we scaled our data proportionally based on the averaged load in the training dataset for each hour.

In the baseline market, the DAM price is derived from the marginal cost function for conventional generation evaluated on the expected net load (i.e., load minus expected total renewable generation from the training dataset). In the proposed market, the DAM price parameter, α, is obtained by taking the expected value of the marginal costs of the training dataset, while real-time adjustments were still determined by the actual marginal cost function.

Figures 2-4 show bar charts comparing the expected values of several market metrics, namely conventional profit, wind profit, solar profit, aggregated renewable profit, and load cost, between the baseline and proposed markets. In the plots, each bar represents the expected outcome of the respective metric. To illustrate the variability in the simulation results, error bars were added. The lower error bar for each metric shows the difference between the mean and the minimum value, while the upper error bar represents the difference between the maximum value and the mean. In addition to the error bars, quantile markers were overlaid on the bar charts to capture the distribution spread; specifically, the 25th and 75th percentiles were computed. For the baseline scenario, red markers (a circle for the 25th percentile and a square for the 75th percentile) were used; blue markers were used for the proposed scenario.

For all hours, the conventional generator profits remained the same in both markets as expected by the theoretical results. Reflecting both the total shortfall and excess scenarios, we focus on results of Hour 0 (midnight) and Hour 12 (noon).

At Hour 0 [Figure 2], we have the total shortfall case. That is, the total renewable generation in RTM was lower than expected (their total allocation in the DAM), so the renewables on the whole need to buy from the conventional to cover this shortage resulting in a lower expected total profit in the proposed market. The load cost is also lower than in the baseline market as expected in the total shortfall scenario.

At Hour 12 [Figure 3], high solar (and wind) generation results in the total excess scenario. The renewables make more money in the proposed market by selling their excess. The total cost to load is more in the proposed new market as expected theoretically.

We also computed the expected revenues for all generators by evaluating the DAM and RTM components separately under both the baseline and proposed markets. In the DAM phase, the conventional revenue was calculated as the product of the net load and its corresponding marginal cost derived via $c_g'(\cdot)$ for the baseline market or the product of the net load and α for the proposed market. Since the renewables only bid in the proposed market, their revenues in DAM are all 0 in the baseline market and are the product of α and their bids in the proposed market. In the RTM phase, we accounted for discrepancies between the actual and expected renewable generation; shortages and excesses were priced using $c_g'(\cdot)$ to obtain the RTM revenue adjustments for all generators. Here is an example plot at Hour 12 [Figure 4].

A. *A Simple Example*

Here, we assume a realistic conventional cost function $c_g(x) = 0.0000146256x^2 + 0.107617x + 1666.72$ derived from analyzing actual conventional generation cost data. Then $c_g'(x) = 0.0000292512x + 0.107617$. Consider the following sample data in Table I of Hour 0 (12am) and Hour 12 (12pm):

Parameter	Hour 0 (MW)	Hour 12 (MW)
d (Load)	57845	61633
w (Wind DAM Commitment)	14288	6027
s (Solar DAM Commitment)	0.40	14523
λ_w (Wind Gen. in RTM)	13853	11646
λ_s (Solar Gen. in RTM)	0.87	15130
μ (Agg. Ren. DAM Commitment)	14288	20551
λ (Agg. Ren. Gen.)	13854	26775

Table I: Example Data with Two Renewable Generators (one Solar and one Wind).

Note that the commitments in the DAM are also the expected generation for the corresponding renewable generators, which is what we assumed to define the conventional generation in the DAM in the baseline practice. For Hour 12, since $\mu < \lambda$, we have the total excess scenario. Therefore, while we expect that the conventional profits be the same in both markets, all renewable generators have greater profits in the proposed market, and the total cost to load is higher in the proposed market as shown in Table II. And Hour 0 corresponds to a total shortfall scenario, where the situation is reversed.

Metric	**Baseline($)**		**Proposed($)**	
	Hour 0	Hour 12	Hour 0	Hour 12
Conv. Profit	26671	23750	26671	23750
Wind Profit	18143	6210	17961	6522
Solar Profit	1.22	20491	1.21	21243
Agg. Ren. Profit	18144	26701	17963	27765
CTL	80108	79636	79926	80700

Table II: Comparison of Profits and Cost-to-Load (CTL) in the Baseline and Proposed Markets.

VI. Discussion and Conclusion

In this paper, we analyzed an electricity market where renewable generators are allowed to bid cost curves into the DAM, just like conventional generators. We analytically derive the expressions for the renewable cost curves so that they take into account the buying (in case of shortfall) and selling (in case of excess) of electricity in the RTM, as needed by the renewable to meet its DAM commitment and utilize its full supply without curtailment. We noted that these cost curves are linear in nature, and of the form $\alpha x_r - \beta_r$, for renewable r. Here, α is independent of r, while the term β_r varies with each renewable, and is representative of power produced in that hour by renewable r. Both these terms require estimation of the price statistics $c_g'(d - \lambda^{TOT}(\xi^s))\, \lambda_r(\xi^s)$ for that hour, which can be made from study of historical prices under a similar weather pattern, or from third party services that specializes in such forecasts.

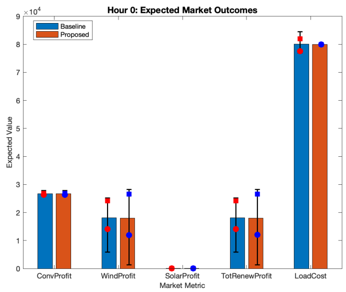

Figure 2: Comparison of baseline and proposed market results at Hour 0.

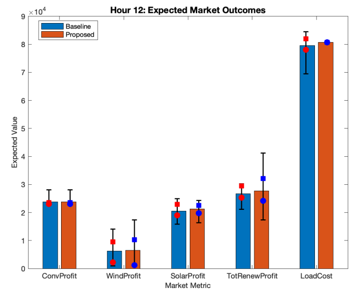

Figure 3: Comparison of baseline and proposed market results at Hour 12.

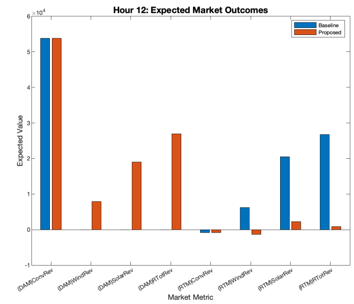

Figure 4: DAM and RTM Comparison of baseline and proposed market results at Hour 12.

Figure 5: Performance Metrics Comparison.

The main contribution of our work is to establish theoretically the equivalence of this market with the current practice in terms of overall system cost, conventional and renewable generator profits, and cost-to-load performance metrics. We demonstrate these theoretical results using data from the Texas grid, considering scenarios where the renewable forecast may not be perfect. These equivalence results shows that it is possible to have renewables bid cost curves into the DAM, and if these cost curves are defined appropriately, the profits of renewables remain the same in an expected sense (i.e., averaged over all scenarios), while the profit of conventionals and cost-to-load remains the same in every scenario.

Despite this equivalence in terms of performance metrics, there are several benefit of the proposed market with renewable bidders are. First, it pushes some of the complexity of market operations under renewable penetration to the edge (namely, the renewables), allowing the ISO to clear the market by solving a deterministic UC problem, while the stochasticity is captured in the calculation of the renewable cost curves that are determined by the renewable generators individually. This avoids the need for the ISO to solve the computationally expensive stochastic UC problem [3], [4]. Second, by allowing renewables to bid cost curves instead of a single number, it allows them more flexibility to incorporate additional risk-tolerance measures into the cost curves. This allows renewables to better manage their risk in the the two-stage market participation than currently possible.

There are several research directions that merit further investigation. Our equivalence results depend critically on the quadratic nature of the conventional cost curves. While this is reasonable and widely assumed in practice, extension to more general convex cost curves remains open. Further, note that we assume total flexibility (liquidity) of the conventional generators (Assumption 4). The commitments of types of conventional generators cannot be changed easily in real-time, or they may have ramp-up/down constraints. Such a scenario would result in renewable curtailment, and needs to be investigated further.

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