Enhancing Price Formation Process in Electricity Markets to Support Advancing High Renewable Energy Targets: A PJM Case Study

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\textbf{1. Overview:} Successfully managing the evolution of electricity grids comes down to ensuring the grid is flexible enough to deal with the characteristics of variable renewable electricity (VRE). For conventional generators, operational flexibility represents their ability to ramp and cycle over various time frames to follow the fluctuations of demand and VRE. Paradoxically, the pricing mechanisms in electricity markets today are not designed to incentivize flexibility attributes of conventional generators with continued growth in VRE. This study investigates the scale and type of inefficiencies posed by conventional pricing mechanisms, and how these inefficiencies serve as a barrier to incent operational flexibility with continued growth in VRE. We also study the implications of alternative pricing mechanisms designed to overcome such inefficiencies.

\textbf{2. Background:} The conventional pricing scheme in spot electricity markets follows the principles of marginal cost pricing that assumes convexity of the supply costs, but the energy bid costs for supply are inherently non-convex as the supply cost is a non-convex function of the output. The non-convexities arise from supply offers of conventional generators that represent start-up and shut-down costs, indivisibilities, minimum up and down times, minimum supply requirements, amongst others. Due to non-convexities, the generation costs do not monotonically increase with demand resulting in prices that do not reflect “true marginal costs” of electricity, which here we define them as the most expensive bids dispatched by the ISO to meet the demand. In fact, as the committed capacity and dispatched generation increases to meet the demand, the prices may remain constant or decrease failing to recover the marginal fuel costs for all suppliers who have cleared the pool to meet the demand. In fact, the prices do not support the market equilibrium determined by the market operator, a.k.a Independent System Operator (ISO); thus, suppliers may deviate from ISO’s welfare-maximizing dispatch instructions as they do not match suppliers’ profit maximizing dispatch schedules at the promulgated prices (Kuang, Lamadrid, and Zuluaga 2019; Scarf 1994). In addition, conventional marginal prices do not reflect the fixed startup, shutdown, and no-load costs, and that can further discourage suppliers from following the ISO’s dispatch instructions if such costs are not completely recovered by the prices.

To avoid welfare loss and ensure reliability, the US ISOs have adopted a two-tier pricing scheme that supplements uniform market clearing prices with discriminatory out-of-market uplift payments that guarantee cost recovery for all suppliers. Such uplift payments ensure all suppliers who follow the ISO’s dispatch instructions and have offer costs greater than the price are paid as bid to make them whole. Uplift payments are useful incentives for maintaining reliability in tight system conditions, but they can erode the other market incentives if they replace a significant chunk of the market. With the growth of make-whole payments, suppliers who frequently receive the make-whole uplift payments have less incentives to bid their actual operation costs, to invest in reducing their marginal production costs, and to invest in improving their performance, e.g. ramping capability. A great deal of the recent research has focused on alternative pricing mechanisms that yield equilibrium supporting prices with lower uplift payments (Liberopoulos and Andrianesis 2016). Gribik et al. concluded that convex hull marginal pricing minimizes the uplift payments (Gribik, Hogan, and Pope 2007). Gribik et al. also proved that the convex hull prices are obtained by finding dual maximizers of the Lagrangian dual of the unit commitment economic dispatch (UCED) problem. The UCED is the optimization problem that ISOs solve to clear the market and determine the socially-optimal commitment and generation dispatch schedules. Nonetheless, Lagrangian dual of the unit commitment problem is convex but non-smooth, and with that none of the proposed solution methods guarantees convergence to the exact dual maximizers in polynomial time. To address the computational issues, Bowen et al. developed a computationally efficient primal formulation of the convex hull that can be solved in timeframes desired by ISOs for large-scale systems (Bowen and Baldick 2017). In the proposed primal formulation, convex hull prices are dual variables associated with the nodal power balance constraints. Bowen’s primal approach tightens the unit commitment formulation around the integer feasible solution point so its linear relaxation would be a close convex approximation of the integer solution point.

Uplift payments have attracted attentions from the Federal Energy Regulatory Commission (FERC) and ISOs, and they have initiated efforts to lower the uplift payments. Nonetheless, preserving the conventional marginal pricing or formulating and adopting minimum uplift pricing mechanisms have remained a point of controversy to this day. In particular, the literature has not addressed the implications of conventional and minimum uplift pricing schemes for incenting attributes and services that are essential for economic efficiency of the grid and electricity market operations with continued growth in penetration of VRE.

Higher wind penetration levels can increase the frequency and magnitude of incidents during which conventional marginal prices fall below the supply offers of committed resources due to non-convexities of slow resources. Also, slow-start resources have to cycle more often; thus, fixed no-load and startup costs account for a larger portion of their supply costs, but they are not reflected...
in prices (Daraeepour, Patino-Echeverri, and Conejo 2019). These effects combined can shrink the energy market returns for flexible slow-start resources whose flexibility is critically needed for dealing with intermittency, variability, and uncertainty in wind power generation. Growing frequency of unrepresentative prices, i.e., prices that do not represent the true marginal costs, increases the over-reliance on capacity markets for driving market entry and exit decisions, which is deemed inefficient and is undesirable. The unrepresentative prices reduce the infra-marginal revenues in the energy market, which would aggravate the missing money problem and result in an increase in capacity market offers and the net Cost of New Entry (CONE). Nonetheless, capacity markets provide no incentive for enhancing flexibility attributes. A capacity market is a construct to incent aggregated capacity attributes, such as maximum generation capacity and low forced outage rates, and not the operational flexibility attributes.

3. Research Objectives and Results: The objective of this paper is to fill this gap and evaluate performance of the markets with the conventional marginal cost pricing mechanism and primal convex-hull pricing mechanisms under various wind penetration levels. Comparing the market prices show how and to what extent the change in cycling and dispatch patterns of conventional resources, which are driven by growth in penetration of wind resources, can drive a gap between conventional and convex-hull prices and the resulting uplift payments. We also evaluate how the frequency and magnitude of incidents in which conventional prices fall below “true marginal costs” grow with wind penetration and drives uplift payments. The gap between conventional and convex-hull prices affect the producers’ surplus and its distribution among various generation technologies. Comparing the annual gross margin in the energy market for various technologies with various degrees of flexibility will also show the role of pricing mechanisms in incenting operational flexibility attributes at high wind penetration levels.

4. Method: To answer the above questions we simulate daily day-ahead market outcomes for an entire year with three different marginal pricing mechanisms: 1) the conventional marginal pricing (C-MP), which represents the model used by the ISOs in the US electricity markets, 2) approximate convex-hull marginal pricing (A-CHMP), which represents primal approximation of convex-hull pricing, and 3) restricted convex-hull marginal pricing (R-CHMP), which is similar to A-CHMP except it freezes the commitment of offline producers and does not allow them to participate in the price formation process. We run the simulations using Electricity Market Simulation Tool (EMST), developed and presented in (Daraeepour, Patino-Echeverri, and Conejo 2019), to simulate electricity market and grid operation outcomes in systems where VRE represents a large share of the resource mix. EMST integrates various unit commitment and economic dispatch optimization models to properly represent various stages of the DA and RT market clearing and grid operations. (Daraeepour, Patino-Echeverri, and Conejo 2019) presents the integration of models, flow of information among them, and the market design assumptions used in EMST to simulate competitive operation of DA and RT electricity markets. For this study, we have extended EMST to simulate market prices, settlement of energy transactions, and out-of-market uplift payments under the conventional and alternative marginal pricing schemes.

We run the simulations on a stylized test system, developed in (Daraeepour, Patino-Echeverri, and Conejo 2019), that combines a 12% version of PJM’s conventional resource mix, accounting for 20,000 MW installed generation capacity, with wind and demand data from Bonneville Power Administration (BPA) to simulate higher wind penetration levels.

5. Conclusions: Conventional generation resources are the major source of flexibility for dealing with variability and intermittency in production of wind energy resources. Conventional resources have to cycle and ramp more often and their fixed startup costs account for a bigger portion of the operation costs for flexible generation technologies. At the same time, change in cycling and dispatch patterns increases the frequency of prices that do not represent the true marginal cost of supplying demand. Combination of the cycling and dispatch patterns and the resulting prices, under the conventional pricing mechanism, can reduce the annual gross margin for investment in or provision of operational flexibility by conventional resources.

6. References:


