Generator Revenue Sufficiency in Electricity Markets with Variable Renewable Generation

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Overview

In electricity markets, the ‘capacity adequacy problem’ arises when electricity supplier revenues are insufficient to incentivize investments in an adequate level of new capacity [1]. Such revenue shortfalls may stem from administratively determined price caps that are implemented to alleviate the potential for exertion of market power during periods of supply scarcity. While price caps limit consumer exposure to unbounded prices, they also limit the revenue available to generators during these periods. As a result, generators may not be properly incentivized to contribute to system reliability during periods of extreme supply scarcity. In addition, new generators may be discouraged from entering the market at all, possibly resulting in insufficient capacity to serve demand and support system reliability over the long term.

These issues are further augmented by the rapid expansion of variable renewable generation (VRG), such as wind and solar, which introduce two additional challenges to system operation. 1) VRG resources have near-zero, zero or even negative marginal costs (due to subsidies) and therefore reduce wholesale electricity prices when they provide the marginal unit of generation in a power system. 2) VRG resources have variable output profiles with limited predictability. As a result, flexible resources become more important in a power system with large amounts of VRG, which must maintain additional reserve capacity to ensure system reliability in periods when generation deviates from the forecast. Under many existing market design mechanisms the provision of reserve capacity and other ancillary services are not always appropriately compensated. Therefore, higher reserve requirements may also increase the revenue shortfall experienced by generators and intensify the capacity adequacy problem.

Power markets in the United States and around the world have implemented a number of different policies to provide generators with sufficient revenue streams so as to motivate generation investments and new entry to the market with the aim of ensuring long-term capacity adequacy [2]. In this paper, we build on our previous work [3], [4] and investigate the impact of the following policies on revenue sufficiency and capacity adequacy:

1. Fixed Reserve Scarcity Pricing (FRSP) – The system operator sets target levels for various reserve products. In the event that a given reserve target is not reached, the price of that particular reserve product is set to an administratively determined scarcity cost.

2. Operating Reserve Demand Curves (ORDC) – The system operator values reserve capacity on the basis of a continuous demand function, which is based on a probabilistic assessment of the contribution of reserves towards system reliability. As reserve levels increase, their marginal value and market price decreases. This approach was recently implemented in the ERCOT system in the state of Texas [5].

3. Capacity Payments (CP) – The system operator provides revenue to generators for having available capacity, independent of the amount of electricity they generate.

4. Uplift Payments (UP) – The system operator implements a mechanism to compensate generators over a period of time (e.g. one day) during which they were instructed to generate, but received insufficient revenue to cover their fixed and variable operating costs. This occurrence is a consequence of non-convex cost elements that are not reflected in energy prices.

Methods

We apply a mixed-integer linear programming model [3] to minimize the cost of generation unit expansion, hourly commitment and dispatch, and reserve provision in the ERCOT power system. Thermal generation units are grouped into four characteristic types and represented by integer variables. This dramatically reduces runtime as compared to a binary formulation that explicitly tracks individual units [6]. The expansion model is applied to analyze the four previously described market policies in the ERCOT system for a future state with VRG penetration that varies from 10% to 40% of total generation. We also conduct a sensitivity analysis around the fuel price of natural gas.

Results

We find that with baseline parameter assumptions, all new generation capacity is developed in the form of natural gas combustion turbines under each market policy. Optimal expansion plans are similar under the FRSP and ORDC formulations, and more additional capacity is developed when capacity payments are provided.

The average wholesale electricity price decreases with increasing wind penetration under all market policies. This is primary due to the fact that wind units increasingly supply the marginal unit of generation. In contrast, reserve prices increase with higher wind penetration, but this effect is generally not as significant as the impact on energy prices. While average electricity prices are comparable under both the FRSP and ORDC formulations, the ORDC approach results in a smoother spectrum of prices with fewer extreme prices spikes. Hourly prices exceed $100/MWh during 823 (out of 8760) periods under the FRSP approach and only 92 periods under the ORDC approach at the 40% wind penetration level. When capacity payments are implemented in the absence of any other revenue mechanisms average electricity prices are much lower, and the hourly price exceeds $100/MWh during only a single period when demand is curtailed. With a fixed capacity payment of $40/kW-year, generator profits are consistently lower than they are under either the FRSP or ORDC mechanism.

Profits for nuclear, coal, and wind units generally decrease with increasing VRG, while profits for natural gas units generally remain consistent under all market policies. The natural gas units are less exposed to lower electricity prices during off peak periods and they receive additional revenue due to increased reserve prices. Uplift payments are calculated ex-post and therefore do not impact the optimal expansion plan in our analysis. Natural gas units receive the greatest benefit from uplift payments due to their higher relative operating costs. Coal units receive uplift payments only when wind penetration is 20% or greater, and nuclear units only when wind penetration is 30% or greater. Payments are also only triggered for nuclear and coal units during days when wind generation is high and negative energy prices result. Natural gas units receive relatively greater uplift payments at all wind penetration levels, however these transfers still account for a fairly small fraction of their total unit revenue under the FRSP and ORDC, typically on the order of 2-3%. Uplift payments for natural gas units are generally 3-5 times greater under the capacity payment framework, however total revenues are still less than under FRSP or ORDC.

A sensitivity analysis reveals that these results are highly sensitive to the cost of natural gas as a fuel source. When natural gas prices reach $10/MMbtu (compared to $5.15/MMbtu under baseline assumptions), new nuclear and coal units are included in the optimal expansion plan at the lower wind penetration levels. Higher natural gas prices also drive up average electricity prices and increase the profitability of coal and natural gas units. A reduction in the natural gas price to $3/MMbtu does not change the optimal expansion plan compared to baseline conditions, but does reduce the profitability of existing coal and nuclear units.

Conclusions

Our results indicate that energy markets with ORDC or FRSP can both ensure revenue sufficiency and capacity adequacy. However this will depend on the design of each framework and the choice of key administrative parameters, such as the reserves scarcity prices and the definition of the ORDC itself. We show that an ORDC implementation can be structured to result in optimal unit expansion plans and generator revenue levels that are comparable to those obtained under a FRSP implementation. The ORDC formulation results in a more continuous spectrum of wholesale electricity prices with fewer large price spikes when scarcity events occur. This could reduce operational and investment risks for generators and may also help alleviate concerns over potential market manipulation. The capacity payment policy leads to more investment in generation capacity, but increasing revenue sufficiency problems, particularly for base load generators, as energy prices are reduced due to more capacity being available. Uplift payments provide an additional source of generator revenue, but as they are allocated ex-post after the market clears, they do not directly impact energy prices or investment decisions in our formulation.

References

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