Reviewing Progress in PJM's Capacity Market Structure via the New Reliability Pricing Model

The Reliability Pricing Model introduces significant changes to the capacity market structure of PJM. The main feature of the RPM design is a downward-sloping demand curve, which replaces the highly volatile vertical demand curve. The authors review the latest RPM structure, results of the auctions, and the future course of the implementation process.

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I. Introduction

PJM is a regional transmission organization (RTO) operating the largest competitive wholesale market in the U.S. PJM area covers all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia [1]. The main characteristics of the PJM area are presented in **Table 1**. As an RTO, PJM coordinates generation and transmission within its footprint. In addition, PJM operates and supervises the capacity obligations of load-serving entities (LSEs) in order to ensure that the system has an adequate level of generating capacity to meet its reliability requirements [2]. In August 2005, PJM filed its proposal for a new capacity market design, RPM, to be implemented in PJM area. After

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Table 1: PJM Area Characteristics

Population	51 million
Generating capacity	164,905 MW
Peak demand	144,644 MW
Annual energy delivery	729,000 GWh

Source: PJM Web site.

several modifications to the original RPM proposal, the Federal Energy Regulatory Commission (FERC) approved PJM's RPM application in December 2006 [3]. The RPM design suggests significant changes in the capacity market structure of the PJM. RPM replaced PJM's old capacity construct on June 1, 2007.

According to the PJM Reliability Assurance Agreement (RAA), PJM LSEs are required to procure capacity resources on an unforced capacity basis at one times the forecast pool requirement above their peak load [4]. Capacity resources could have been acquired through bilateral agreements or through the PJM-operated capacity market. In its FERC filing PJM asserted that the old capacity construct had three main flaws [5].

1. *Lack of locational element*: Although the system's transmission capacity varies by location, the capacity price was same across the PJM footprint. This situation resulted in improper allocation of capacity resources within PJM region, as excess capacity in the west was socialized throughout the constrained portions of the system.

2. *Capacity price volatility due to vertical demand curve*: Under the capacity credit market structure, the cost of a new peaker unit was assessed as a capacity deficiency charge if the LSE was short of its reserve margin requirement. If there was a surplus of even a few megawatts of capacity, then the capacity price would drop to zero. This situation created highly volatile capacity prices, which are oversensitive to capacity resource availability.

3. *Short-term commitment of the capacity resources*: The previous reliability structure allowed capacity resources to be devoted as short as one day. In addition, capacity resource suppliers could withdraw their resources with 36 hours' notice. These features were in conflict with the reliability preservation efforts in the system.

In its April 20, 2005 order FERC stated that ''PJM's existing capacity construct is unjust and unreasonable'' [2]. In the same order the FERC also found some aspects of the PJM's RPM proposal, namely ''locational capacity requirements; a four-year-forward procurement auction; a downward-sloping demand curve, integration of generation, demand response and transmission; and the proposal for treatment of quickstart and load-following generation'' [2], to be just and reasonable.

The RPM mechanism addresses the three reliability concerns mentioned above as well as some others such as market power mitigation, quick-start, demand response, and transmission participation. In addition, it guarantees that new peaking capacity will be built in equilibrium by solving the ''missing money'' problem.

II. Why Are Capacity Markets Needed? The Missing Money Problem

The ''missing money'' problem was first characterized by Roy Shanker [6] and arises when occasional market price increases are limited by administrative actions. There are two kinds of price spikes in an energy-only market. During energy price spikes, prices are set by the cost of an inefficient marginal unit at $100–150/MWh. During scarcity price spikes, prices are set by the value of lost load (VOLL) at up to $10,000/MWh [6]. New peakers, operating in very few hours per year, must dispatch in both periods to recoup their variable (dispatch), fixed, and capital costs. PJM has estimated that peakers earned $19–21/kW-yr in 2001–06 from dispatch during periods of energy price spikes (Table 4). To recoup capital costs, estimated at $72/kW-yr, new peakers must capture at least $50/kW-yr in periods when prices are set by the full value of lost load. A reference, 171 MW peaker located in a marketplace experiencing scarcity prices for 6 hours per year will earn $60/kW-yr, enough to make back its costs. If prices are capped at $1,000/MWh (which is the FERC-mandated price cap in the U.S. marketplace) during these periods, new peaking units will only capture $6/kW-yr. Absent regulatory intervention,