PJM Reliability Pricing Model – A Summary and Dynamic Analysis

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***Abstract*—The Reliability Pricing Model (RPM) is the capacity construct proposed by PJM to implement forward procurement of generating capacity requirement recognizing its locational value. A Variable Resource Requirement (demand curve) is used to determine the amount paid to capacity. Capacity market buyers, sellers and other parties developed a Settlement Agreement and filed it with US Federal Energy Regulatory Commission (FERC) in September 2006. Subject to FERC approval, RPM is scheduled to replace the current capacity market effective June 2007. This paper summarizes the key features of the RPM proposal, and the results of a dynamic comparison of the Settlement Curve with other possible curves.**

***Index Terms*-- Economics, Power generation peaking capacity, Power generation economics.**

I. Introduction

PJM has been using the Loss of Load Expectation (LOLE) criterion to determine the adequacy of installed capacity (ICAP) requirement. The criterion is that load shall not exceed the available capacity, on the average, more than one day in ten years. The ICAP required to meet this criterion is expressed as percent reserve above the 50:50 forecast peak load.

PJM developed a method to calculate 'equitable' allocation of pool ICAP requirement to the member systems in 1974. The method considered resource related factors (forced outages, planned outages, and energy limitations) and load related factors (peak load forecast, seasonal patterns, and forecast error) that impact reliability. A capacity deficiency rate based on an annualized cost of combustion turbine was used to penalize a member utility that was short of meeting the capacity obligation allocated by the pool.

The use of the forward capacity obligation method helped the PJM member utilities to plan and build the required generation and the pool maintained the reserves needed to meet the reliability criterion. The method was used from 1974 to 1998 and modified in 1999 with the introduction of generation deregulation and retail access. The modification changed the forward obligation to a daily obligation concept for loads but retained the basic reliability assessment method and the loss of load probability criterion.

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PJM is one of the Planning Reserve Sharing Groups (PSRG) of the new NERC region ReliabilityFirst formed on January 1, 2006. ReliabilityFirst confirmed the standard that each PSRG shall meet the Loss of Load Expectation of one day in ten years and have agreements to enforce resource planning reserve requirement on its Load Serving Entity (LSE) members.

II. Need To Modify The Current Installed Capacity Construct

Although PJM as a whole has sufficient generating capacity today, the pace of generation development has slowed with the supply in excess of the requirement and lower capacity prices. Since under deregulation of generation investors have no obligation to meet the regional Resource Adequacy mandate, it is critical for a PRSG to design the appropriate markets that incent the existing generation to stay and the needed new generation to be built. This means that resources must receive adequate revenues. In particular, since the peaking generation needed to meet the adequacy criterion will not receive enough revenue from the energy market to justify investments, other revenue streams are needed to ensure that they cover their fixed costs. The gap between the net revenues and fixed cost of generation is referred to as "Missing Money".

The PJM State of the Market report for 2005 [1] shows that the average of all net revenues during 1999-2005 was below the level needed to cover the full cost of new generation investment. Generating units essential for reliability in some areas did not receive revenues needed to cover their going forward costs and the owners wish to retire them. Today generation can be retired with 90 day notice which is too short to develop alternate resources that may be needed to maintain area reliability. These facts suggest that market price signals and reliability needs are not adequately synchronized and there is a need to provide forward price signals and also to recognize locational value of capacity.

The goals of a good market may also include predictability of system adequacy and reduction of boom-bust-cycles to reduce investment costs and risks. Since the levels of reserve margin achieved impact the scarcity (energy) prices, an additional goal of the market can be to minimize costs to consumers.

III. THE ESSENTIAL ELEMENTS OF RPM

To address these goals, PJM proposed the Reliability Pricing Model (RPM), a new capacity market construct. The proposal, which was originally filed at FERC in August 2005 and subsequently modified in the September 2006 settlement, includes the following key elements:

Forward market: A centralized auction is conducted three years in advance of the delivery year to procure the required resources on behalf of the load. This process provides clear price signals to the market well in advance. Generating capacity not yet built can be offered based on its net cost of new entry. Forward price signals tend to reduce "Missing Money" since a new generating unit would be built or an existing generating unit would be offered (and not retired) only when the price is 'right'. The RPM is a better, competitive solution than the short-term alternative of negotiating special, non-competitive contracts, known as "reliability must run" contracts, to prevent plants from being retired. Forward commitment of new resources and retirement decisions would help the PJM Regional Transmission Expansion Planning Process (RTEPP).

Locational value: Resources in locations experiencing area reliability problems due to transmission import capability constraints would be valued higher and resources in locations with excess would be valued less. Uniform prices regardless of location, in particular a low price with excess capacity in the system, does not incent the new generation needed in constrained locations. Standard area reliability evaluation techniques are used to define a constrained area and its physical resource requirement.

Demand curve: The VRR (demand curve) is a relationship that defines the maximum price load is willing to pay for different levels of resources relative to the resource requirement. The price is higher when the resources are less than those needed to meet the adequacy criterion and lower when resources are in excess. The recommended shape, height, and location of the curve is determined based on a study of different curves and their impact on generation investment required to meet the Resource Adequacy standard. The demand curve recognizes the value of excess capacity above the level needed to meet the adequacy criterion and provides some revenue under those circumstances. This process would tend to stabilize the market prices and reduce the investment risk.

Other features: Various other features included in RPM are:

- RPM promotes direct competition among generation, demand resources and transmission solutions.
- RPM includes the continued use of self-supply and bilateral contracts to meet capacity obligations as a hedging mechanism to load. A centralized auction is conducted to make up the difference, if any, between the amount of capacity required and the amount obtained through self-supply and bilateral contracts.
- Resource Commitment period is one year.
- A transparent capacity price to be charged to load is a benefit to Load Serving Entities in retail load switching decisions.

The original proposal of RPM recognized the possibility of generation with operational characteristics such as load following and quick start receiving a higher price for the additional benefits it brings to the system. However, the Settlement Agreement proposed to include these characteristics as ancillary services.

IV. DEMAND CURVE ANALYSIS

A dynamic representative agent model was used to project the effects upon reserve margins, generator profitability, and consumer cost of alternative capacity demand curves proposed for the PJM market. The object of the dynamic model is to assess how alternative assumptions concerning investor behavior could affect the performance of different demand curves, considering the dynamic response of the market to construction incentives. Details on the methodology are presented elsewhere [2].

Here we update that analysis by discussing the comparison of the curve that was agreed upon in the settlement (the "Settlement Curve") with the original RPM VRR proposed in August 2005 by PJM. The Settlement Curve reflects some adjustments that were agreed upon to decrease payments when reserve margins are high, and to lower the maximum amounts paid.

Two indices of curve performance are considered here:

1. Resource adequacy index: the fraction of years in the simulation in which the forecast reserve margin exceeds the target ("Installed Reserve Margin") of 15%.
2. Consumer cost: We calculate the mean of customer payments ($/peak MW/year) for capacity plus scarcity rents paid to all capacity. Average cost can be high if low reserve margins are experienced, yielding high capacity prices and scarcity payments. Such conditions could persist if high market risks make investors reluctant to construct unless average returns are large.

Because some of the controversy over the Settlement Curve proposal revolved around the degree of risk aversion that investors would exhibit and its implications for the performance of the curves, we summarize some results for different levels of risk aversion. The assumptions and results of the analysis will be discussed in more detail in the presentation.

Risk aversion is parameterized in the dynamic model by a coefficient that determines the degree of concavity in a risk averse utility function (see [2]). A coefficient of 0.5 implies complete risk neutrality (investors care only about long term average returns, and not their distribution), while higher values imply increasing degrees of risk aversion (penalization of investments that exhibit more variable returns). As explained in [1], the base case risk aversion coefficient was assumed to be 0.7. The results under that assumption were:

- August 2005 PJM proposal: 98.4% chance of achieving IRM, consumer cost = 79.2 $/peak MW/yr.
- Settlement Curve: 95.2% chance of achieving IRM, consumer cost = 82.1 $/peak MW/yr.

Thus, the differences between the two curves based on consistent assumptions are negligible under these assumptions, with the Settlement Curve with slightly inferior performance.

The results under some alternative assumptions are as follows:

Low risk aversion (0.6):

- August 2005 PJM proposal: 98.0% chance of achieving IRM, 77.7$/peak MW/yr consumer cost.
- Settlement Curve: 92.7% chance of achieving IRM, 80.7$/peak MW/yr consumer cost

Thus, with a smaller degree of risk aversion than the base case value of 0.7, Curve 4 and Settlement curve perform similarly.

Moderately high risk aversion (0.8):

- August 2005 PJM proposal: 95.5% chance of achieving IRM, 83.9$/peak MW/yr consumer cost.
- Settlement Curve: 92.5% chance of achieving IRM, 84.8$/peak MW/yr consumer cost

Therefore, under a larger degree of risk aversion than the base case value of 0.7, the Curve 4 and Settlement curve perform similarly.

High risk aversion (0.9):

- August 2005 PJM proposal: 90.6% chance of achieving IRM, 91.7 $/peak MW/yr consumer cost.
- Settlement Curve: 65.7% chance of achieving IRM, 107.2 $/peak MW/yr consumer cost.

Given this extreme risk aversion, these differences are larger than under the base case assumption of 0.7.

Thus, under a range of degrees of risk aversion (except for the most extreme value), the curves perform similarly.

V. Conclusion

In a deregulated environment, designing proper capacity market is as important as determining installed capacity requirement to meet the reliability criterion. The market should provide stable and adequate revenues to existing generation to stay in service and new generation to be built.

This paper describes the new capacity market construct, Reliability Pricing Model, proposed by PJM that includes forward procurement of capacity, locational value and demand curve.

Future analyses should consider the dynamics of locational markets, in which capacity needs in local demand areas can be met locally or by imports of capacity. The interaction of generation investment and transmission constraints should be explored. Also, the adjustment over time of the demand curve should be considered; the above analysis assumes a fixed curve, whereas the RPM proposal involves adjustments over time in response to experience with accepted capacity bids.

VI. References

[1] PJM Interconnection, LLC, "State of the Market Report, 2005", 2006.

[2] B.F. Hobbs, M.-C. Hu, J.G. Inon, S.E. Stoft, and M. Bhavaraju, "A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model," *IEEE Trans. Power* Systems, in press.

VII. Biographies

Murty P. Bhavaraju (F'87) received a Ph.D. in electrical engineering from University of Saskatchewan, Canada. He worked in the area of system planning for 35 years at PSE&G and joined PJM Interconnection in 2004 as a Senior Consultant. He served IEEE in the past as the chairman of Application of Probability Methods Subcommittee, Power System Engineering Committee, and Fellow Evaluation Committee, and recently as the Editor in Chief of Transactions on Power Systems. His interest has been power system planning with special focus on reliability assessments.

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