UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, LLC) **Docket Nos.: EL05-1410-000**
EL05-148-000

Comments Of Gary R. Sorenson, Managing Director, PSEG Power LLC
On Behalf Of The PSEG Companies
(February 3, 2006 Technical Conference)

Good afternoon. My name is Gary R. Sorenson. I am the Managing Director of Energy Operations for PSEG Power, LLC. I appreciate the opportunity to appear before the Commission this afternoon to discuss PJM's Reliability Pricing Model ("RPM") on behalf of PSEG Power LLC, PSEG Energy Resources & Trade LLC and Public Service Electric and Gas Company ("the PSEG Companies").

The PSEG Companies fully support the key elements of the RPM proposal. I will summarize them briefly. The first key element of RPM is the forward procurement mechanism. PSEG believes that the proposed four-year outlook will provide a much better signal for the entry of potential capacity resources and will strengthen the transmission planning process by providing much longer lead times for identifying capacity deficiencies in constrained areas. The second key element is the locational capacity component. This is necessary to recognize the reliability benefits associated with capacity resources situated in transmission-constrained areas. As I will discuss in greater detail later, if the current capacity construct had recognized the locational value of capacity resources, it is unlikely that PSEG Power would have needed to seek "Reliability Must Run" ("RMR") payments in order to continue operating 836 MW of capacity in the PSE&G Zone that PJM determined was required for reliability purposes.

The third key component is the downward sloping demand curve used to clear prices in the base capacity auctions. Adoption of this element will add greater stability to capacity prices and reliability levels. This improved price signaling will facilitate new entry of capacity resources by fostering capital formation opportunities for generators and other providers of capacity at lower costs. Fourth, the RPM proposal will place demand side resources as well as economically-driven transmission projects on an equal footing with generation from the standpoint of meeting capacity obligations. This will help in assuring that the optimal economic solution is utilized.

The PSEG Companies believe that adoption of these key RPM elements will improve reliability by reducing fluctuations in the level of capacity reserves needed to meet established reliability criteria and will improve the transmission planning process by providing a longer planning horizon. The PSEG Companies further believe that RPM will result in savings to consumers. RPM will enable capital formation needed by developers of capacity resources to occur at lower costs and will help avoid the need for interim RMR arrangements. Also, because RPM is designed to encourage the retention of capacity resources at levels greater than the bare reserve requirement, it should also result in lower energy prices.

The PSEG Companies believe, nonetheless, that the current RPM filing could be improved in certain respects. In particular, the manner in which RPM treats older generating units located in constrained areas should be reconsidered. As currently proposed, RPM could lead to the premature retirement of such capacity resources in certain cases. The PSEG Companies are especially familiar with the problems facing older generating units because their generating fleet includes a number of older plants located within transmission-constrained areas.

PSEG Power owns a diverse fossil fleet in central and northern New Jersey which includes a number of older, less efficient generating plants. Transmission constraints within these areas occur on a regular basis and, based on presentations made by PJM in stakeholder meetings, these areas are expected to become "Locational Deliverability Areas" after RPM is fully implemented. Since October 2003, PSEG Power has retired approximately 686 MW of generating capacity in New Jersey. Based on age and condition, other plants could be candidates for retirement at a future date. From a physical standpoint, the useful life of a generating plant is often determined by the physical condition of key plant components such as boilers and turbines. When these facilities suffer a complete breakdown or appear to be approaching the point of breakdown, retirement of the unit or prohibitively large capital outlays are likely the only options.

In many cases, however, the physical life of older plants can be sustained for extended periods if the units recover sufficient market revenues to fund robust maintenance programs. When that is not the case and the units do not make enough even to support normal maintenance activities, the market is then telling the units they are not sufficiently valuable to justify such expenditures. If that occurs, the units may be operated in "harvest mode," by which I mean that minimal maintenance needed to meet safety concerns will be preformed and the units will be operated until they break a major component. Sometimes, however, the unit may not earn even enough to cover the costs of a curtailed maintenance schedule and the direct costs of day-to-day operations. If that is the situation, the market is saying that the unit should be retired immediately.

In September 2004, PSEG Power advised PJM that it intended to retire 836 megawatts of generating capacity associated with four units located at the Sewaren facility – all of which were then more than 50 years old -- and a unit located at PSEG Power's Hudson location which was then more than 40 years old. In fact, these units were sustaining out-of-pocket losses even though they were being operated in what I referred to earlier as "harvest mode." As noted in the letter advising PJM of PSEG Power's intent to retire the units, the company was unable to continue operating the plants without a pricing mechanism that provided adequate compensation. PJM subsequently determined, however, that the Sewaren and Hudson units were needed by PJM for reliability purposes until transmission upgrades, planned for completion in 2008, could be built. In April 2005, these plants thus became the first units located within the PJM footprint to obtain RMR treatment from PJM under PJM's new retirement policy that had gone into effect in January 2005. Under the PJM tariff, PSEG ER&T applied for and ultimately received Commission approval to provide reliability services from the plants at rates reflecting their cost of service, net of market revenues, until the necessary transmission upgrades can be completed. PSEG Power therefore has experience in addressing the economic considerations of owning and maintaining older plants located within areas in which they are needed for reliability purposes.

The current provisions of RPM, however, do not take full account of the physical and economic characteristics of older plants and could result in the premature retirement of such facilities. Under the RPM proposal, the owner of any capacity resource that appears to be physically capable of operating in the Delivery Year must be offered by the owner of the unit into the base capacity auction. Further, if the unit is located within a Locational Delivery Area and that area does not pass PJM's three jointly pivotal suppliers test, bid price caps become applicable. Under these price caps, the owner of the unit may not bid more than its "Avoided Costs" associated with that unit. Avoided Costs, as defined in the PJM tariff, consist of direct costs incurred to enable the unit to participate in the energy market, such as the cost of labor for on-site activities, property costs and corporate level expenses directly related to the unit. The definition of Avoidable Costs does not include any indirect costs or any return on investment. A 10% adder is allowed but is recognized by PJM as constituting a "fudge factor" due to the difficulties of precisely determining Avoided Costs rather than a return component.

The PSEG Companies take issue with this construct in several respects. The first issue concerns the "must offer" obligation as applied to older generating units. While there may not be an obvious and observable reason why an older generating unit will be physically incapable of operating four years into the future, the owner of the unit may still have legitimate concerns about the unit's physical condition at that time. All plant components have some limit on their useful life and old plant components are more likely to have problems. Requiring the committment of an older generating unit four years into the future imposes unfair risks on the unit's owner because if the unit does fail prior to the Delivery Year, the owner will be obligated to obtain replacement capacity, perhaps at much higher prices. This "must offer" rule should be modified to allow older units which can demonstrate legitimate long-term operating concerns to be bid into near-term auctions rather than the four-year advance auction. This will provide a reasonable procedure to retire an aging and deteriorating unit as it reaches the end of its physical life. If the "must offer" rule is not modified, however, it may create perverse incentives to retire older units prematurely in order avoid the risk associated with a four-year advance commitment.

Second, owners of older generator units should be given the option to bid the full cost of service of such units when there has been a cost of service determination obtained from the Commission or the owner is willing to obtain one. Mr. Bowring, PJM's Market

Monitor, indicates in his testimony in the RPM filing that "[a] rationale seller will offer capacity into the capacity market at a price that covers its avoidable costs, net of energy and ancillary services revenue. It is profitable to sell at any price in excess of that price and it is not profitable to sell at any price less than that price" While I agree that this holds true as a general matter it does not necessary hold true for a generating unit approaching the end of its useful life. As I explained earlier, it is difficult to forecast the condition of an old generating unit at a remote future date. A generator that suffers catastrophic failure in the three years following an auction would never realize any profit if the owner of the plant were required to obtain more expensive replacement capacity.

In addition, in cases in which the unit's Avoidable Cost rate is close to the demand curve clearing price, an older generating unit that is physically capable of operating still may never realize any profits. If the generating unit only recovers its Avoidable Costs for several years and then, in response to higher clearing prices for capacity in the Locational Deliverability Area, new capacity is built that displaces the old generating unit, the unit's operations would never become profitable. Older generating units – especially ones for which retirement seems to be a possibility -- should be allowed to bid their full cost of service. If the level of the full cost of service exceeds the corresponding clearing price on the demand curve, the owner would receive a clear signal that retirement is appropriate.

I would also like to make clear that, just because a unit may be allowed to bid up to its full cost of service, it would not necessarily mean that the bid cap price would exceed the demand-curve clearing prices. For the Sewaren and Hudson units now receiving full cost of service treatment, the base cost of service rate is $ 33.5 million for 836 MWs of installed capacity. Assuming a 10% forced outage unavailability factor, the units would qualify for approximately 752 MW of Unforced Capacity. This results in a rate of $122 per MW-day. Assuming also that the unit has $15 million in yearly project investment costs above and beyond normal maintenance and that the unit is allowed to recover all of these costs in the year they are expected to be incurred, the resultant rate would be $177 per MW-day. This would actually be less than the clearing price that would occur at the 15% Installed Reserve Margin level of $182 per MW-day under the demand curve proposed by PJM for the PSE&G zone. The bid caps for the units, moreover, would be lower if energy and ancillary services revenues were included. Allowing full cost of service bid caps, accordingly, does not necessarily remove the unit from the market under the RPM design.

The third area I would like to mention concerns the manner in which the Avoidable Cost rate is calculated. The PSEG Companies have two concerns in this regard. First, the current definition of Avoidable Costs makes clear that only a share of potentially avoidable costs will ever get recognized. For example, not all of the labor costs incurred at a unit will necessarily be deemed "Avoidable Costs" if the PJM Market Monitor determines that the operator might not be able to redeploy all the affected workers within four years. Such determinations, however, would vest too much discretion in the Market Monitor and, in any event, would not make sense. Under the RPM structure, the Delivery Year is four years in the future from the date in which the base auctions are held. It is unreasonable to assume that, within a four year period, the owner of a generating unit could not avoid incurring all the direct costs of its current operations. The definition should be modified to allow the bid caps to include the full amount of costs within each Avoided Cost category.

The second concern again relates to older units. The Avoidable Cost methodology as proposed in PJM's filing assumes that project investments needed in order to maintain a unit as a capacity resource will be collected over a minimum period of three years. Accordingly, a unit can collect, at most, one third of its investment in the Delivery Year. In the case of older units, the assumption that each project investment will enable the unit to keep operating for at least two additional years beyond the Delivery Year is simply not reasonable. Significant project investments may well be required for an older unit – particularly one that has been operated in "harvest mode" -- in order to enable it to operate only for one additional year. In the subsequent two years, an older unit may well experience even more disabling operational problems which would prevent it from operating or, in response to locational capacity price signals, the unit might be displaced by other capacity resources. Older units thus should be allowed to include the full level of costs associated with project investments in a single year's Avoided Cost bid.

In conclusion, the PSEG Companies fully support the key elements of PJM's RPM proposal and commend PJM for its efforts. The PSEG Companies believe that RPM should be implemented as soon as possible. The main areas in which they believe that RPM could be improved relate to the treatment of older units in order to assure that the proper incentives are in place to prevent premature retirement. Thank you for your time. I am available for questions now or at the end of these presentations.