PSEG Power LLC and PSEG Energy Resources & Trade LLC (collectively “PSEG Power”) hereby submit comments in response to the June 17, 2011 Legislative Hearing and prior written comments filed in this matter. PSEG Power is filing limited responsive comments for the purposes of addressing allegations (i) that the Reliability Pricing Model (“RPM”) and PJM energy markets have not resulted in significant new investment in capacity resources in the State of New Jersey;1 (ii) that the type of capacity resources that have been added under RPM, such as peaking units, do not provide substantial benefits to New Jersey consumers;2 and (iii) that the market construct has failed because it has not resulted in the recent new build of combined cycle (“CC”) gas-

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1 See e.g., “Comments of the New Jersey Division of Rate Counsel,” dated June 17, 2011, (“In sum, in the absence of long-term fixed price contracts, which markets do not now provide, price volatility and the short term nature of RPM contribute to an inability to obtain financing that has become an almost insurmountable obstacle to the construction of new generation serving New Jersey.”)

2 See “Comments of Competitive Power Ventures, Inc.,” p. 1 (claiming that “while the RPM has proven adequate in securing least cost resources for reliability, it does not provide revenue predictability over a sufficiently long enough term to incent new generation resources which offer the features or characteristics that states may value.”)
fired generating facilities in the State. Enclosed is the affidavit of Dr. Roy Shanker, an economist with extensive experience involving energy and market design issues, in further support of these reply comments.

A. As Shown By PSEG Power’s Own Pattern of Capital Expenditures, the RPM Construct has Resulted in Significant Investment in Capacity Resources in New Jersey

Other participants that filed comments and that appeared at the June 17th legislative hearing have discussed the large quantities of new entry capacity resources – including significant amounts of demand response resources – bid into and cleared in the recent RPM auctions. Further, as also shown by the record, many generators have reversed previous retirement decisions and have entered into commitments as capacity resources for periods subsequent to their previously announced retirement dates. A significant share of these resources, moreover, is located in New Jersey. Mr. Ott, appearing for PJM reported that “RPM has added [5,564.9 MWs of] incremental capacity resources available [that] came (sic) at a lower cost to New Jersey than it would have had building those as new resources.” Tr. 9: 1-4

RPM has had a direct and very sizable impact on PSEG Power’s own capital expenditures for generation. This includes the decision to spend to approximately $1.4 billion to construct extensive environmental upgrades for our New Jersey coal plants located at our Hudson and Mercer stations – the Hudson 2 and Mercer 1 and 2 units.

3 Id; see also., “Comments of the New Jersey Division of Rate Counsel,” dated June 17, 2011, p. 11 (stating “those with the abundant cash flow, strong corporate balance sheets, access to economical capital and control over the best sites may have a strong disincentive to add capacity to the market (particularly baseload-type capacity) because doing so would have the effect of moderating supply prices and therefore revenue streams for their existing generation portfolio in the region. Therefore, their profit maximizing strategy is not to build, and even to retire existing capacity that is marginal.”).
This work created substantial numbers of well-paying construction jobs in New Jersey for several years. Further, the performance of this work has transformed these stations into some of the cleanest coal stations in the country. It has also enabled these plants to continue operating in conformance with environmental regulations while providing significant permanent positions of employment at these sites. PSEG Power would not have been in a position to make these capital commitments if RPM had not been in place.

PSEG Power also reversed its decision to retire resources based on RPM. PSEG Power notified PJM of its intention to retire its Sewaren plants in 2004 because the compensation associated with the plants at the time (pre-RPM) was not sufficient to cover either the out-of-pocket cost of operation or the project investments needed to maintain the reliability of the plants. The condition of the plants at the time the retirement decision was made, in fact, had deteriorated significantly because there had been inadequate revenue from the market for several years to justify expenditures. PJM thereafter retained the plant for a time under an RMR arrangement but, in 2008, PSEG Power withdrew the notice to retire because continued future operation could be sustained through RPM revenues.

PSEG Power is currently paying back PJM for the unamortized portion of the project investment payments the Sewaren units received while in RMR status. The Sewaren units are currently committed through the 2014/2015 delivery year and operate within New Jersey environmental requirements to meet peak demand. Similarly, RPM also provided the basis for environmental compliance investments in PSEG Power’s peaking fleet. RPM price signals justified the investment in water injection (a method of NOX reduction) at several peaking facilities, prolonging the fleet’s useful life by several
years. New Jersey consumers have benefited significantly from the life extension of these resources through lower capacity prices and an improved environmental footprint.

PSEG Power has also bid a number of new combustion turbine (“CT”) generating units into several RPM auctions and has cleared six such plants with a total installed capacity rating of about 267 MWs. PSEG Power is currently beginning construction of these units to have them on-line for the 2012/2013 delivery year. The total capital expenditure for this work will be in excess of $250 million. The financial risk associated with this investment activity is entirely borne by PSEG Power. If these units fail to become profitable, New Jersey consumers will not be responsible for any losses. Further, PSEG Power continues to study other peaking projects and several combined cycle units in New Jersey, and is positioned to respond to appropriate price signals from a functioning competitive wholesale market.

In sum, as shown by PSEG Power’s investment decisions, RPM has fostered significant capital expenditures in New Jersey without New Jersey residents becoming responsible for footing the bill if the resources fail to generate sufficient revenues to cover costs. As such, comments asserting that RPM has failed to produce meaningful results or that New Jersey has not seen significant investment activity cannot be reconciled with PSEG Power’s own experience and business decisions.

B. The Construction Of New Peaking Generating Facilities In New Jersey Substantially Benefits New Jersey Consumers

As noted above, PSEG Power has committed to constructing – without subsidies under LCAAP – 257 MWs of new combustion turbines at an expected cost of around $250 million. At the June 17th hearing, however, there did not appear to be any
recognition of the value accorded to New Jersey consumers in connection with these units. In fact, New Jersey consumers do benefit significantly from the development of such plants.

While the construction associated with CT plants does not create as many jobs as constructing a combined cycle plant, meaningful levels of construction jobs are created. In addition, the maintenance and operation of CTs also creates permanent employment. The addition of new combustion turbines also has a material positive effect on the environment. Modern combustion turbine technology – especially when combined with add-on emission controls – operates much cleaner than the older model machines. PSEG is currently constructing six (6) state-of-the-art GE LM6000 simple cycle combustion turbines to replace sixteen (16) older peaking combustion turbines at its Kearny Generating Station.

The new units are equipped with selective catalytic reduction (SCR) systems and oxidation catalysts which significantly reduce nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOC). When the new combustion turbines operate, they will produce >95% less NOx and 70% less VOC than the 16 older peaking units, which will assist New Jersey in attaining the ozone National Ambient Air Quality Standard.

Modern combustion turbines also operate much more efficiently than older models. The higher efficiencies of these machines should result in lower prices during peak periods. In addition, these kinds of unit provide ancillary services and black start capability and will assist in the integration of intermittent resources such as wind that need to be matched with resources that have quick response capability. Consumers will
benefit significantly from these improvements. Peaker technology clearly has role in
developing an efficient generator fleet that will meet the needs of consumers at the lowest
overall cost.

C. The Lack of Recent New Construction of Combined Cycle Generating
Plants Is Not Indicative of Any Failure in Markets

The contention was made at the June 17th hearing and in written comments that
the PJM capacity and market constructs are flawed because no new combined cycle or
“baseload” plants have been built in New Jersey since RPM commenced. The argument
is made that if RPM really is a robust design then the “high prices” cleared for New
Jersey should have resulted in more generation construction. In fact, decisions to deploy
capital to develop new capacity resources to meet generation adequacy needs, i.e., the
goal RPM was designed to achieve, appear to have been entirely rational. Given the
current market conditions, current manner of transmission planning, current policies
towards demand response and the uncertainty associated with regulatory policies
generally, expenditures for capital intensive capacity resources – such as combined cycle
plants – do not appear to be economically justifiable at the present time.

The “price signal” created in the RPM auction does not distinguish between types
of generating resources: a megawatt of capacity gets paid the same regardless of the type
of production technology that supplies it. As explained by Dr. Shanker, the decision by
a developer whether to build a CT plant (the lowest capital-intensive type of generating
plant) or a CC plant (a higher capital intensive type of generating plant) turns largely on

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4 See June 17, 2011 Hearing, Tr. 176 : 6-9, 177 : 11-15 (comments of President Solomon).
5 This is not the case for demand response at least since the auction covering the 2013/2014 delivery year. If Limited DR or Summer Extended DR reaches its saturation level, those types of resources would be paid a lower price. Different types of generating facilities, however, get the paid the same price for each capacity increment.
the energy market.\(^6\) When the net present value of extra expected energy market revenues associated with the increased operating efficiency of a combined cycle exceed the higher capital costs, it becomes economically rational to build the CC. Otherwise, the CT is the economically rational choice.

As shown by Dr. Shanker, using data developed by the PJM Independent Market Monitor, current market conditions in general present significant risks associated with the construction of any type of generating plant. Based on historical market performance, there would be a significant revenue energy revenue shortfall for either a CC or a CT.\(^7\) Further, the IMM data demonstrate that the “conversion benefit,” i.e., the advantage to be gained by building a combined cycle plant as opposed to a combustion turbine, shows a deficiency in revenues. Specifically, the CC would need to earn an additional $44,200 per MW-year in revenues, on average for twenty years, to justify conversion from a CT plant.\(^8\) This is further confirmed by an analysis conducted by Dr. Shanker that compares the price advantage enjoyed by a CC over a CT based on heat rates. In this case, the data show that the energy margin differential would not support the incremental capital associated with the construction of a CC as compared with a CT.\(^9\) Exacerbating this situation is the fact that there are currently significant levels of excess capacity resources in PJM as a whole, depressing both capacity prices and the expected energy margin that can be earned.\(^10\)

Based on all of these factors, to the extent that any new entry of generating plants could be expected to occur, the economically rational decision would be to construct the

\(^6\) Affidavit of Dr. Roy J. Shanker at P 15.
\(^7\) Id.
\(^8\) Id. at P 24.
\(^9\) Id. at P 25.
\(^10\) Id. at P 5.
type of resource with the lowest capital cost. The lower level of capital cost expenditures reduces the developer’s overall financial exposure.\textsuperscript{11} This is compelling in light of how a new entry generating plant would have fared based on historical market performance. In addition, reducing reliance on the energy market by constructing a combustion turbine will tend to lower financial risk by lessening exposure to a volatile revenue source that, would not have provided a sufficient revenue source in the past.\textsuperscript{12}

Indeed, to the extent that PSEG Power can discern contract price information from the report prepared in the first LCAPP proceeding, the results realized in that procurement also appear to support Dr. Shanker’s analysis. As is the case with respect to at least two of the selected projects, the levels of capacity payments appear to be well in excess of any historically observed RPM clearing prices.\textsuperscript{13} Accordingly, for these developers the cost of a CC did not appear to be supported by historical market revenues.

Other factors identified by Dr. Shanker also support the selection of low capital cost capacity resources as the economically rational choice assuming that RPM prices are high enough to justify any new entry. Notably, the current PJM transmission planning process tends to be biased towards transmission solutions because it is more forward-looking (five years) than the RPM advance procurement time frame (just over three years).\textsuperscript{14} This issue could be addressed through reforms in the way that transmission planning and RPM are coordinated. Until these reforms are implemented, however, the disconnect between transmission planning and RPM will tend to cause developers responding to price signals in an LDA to chose the lowest capital cost resources.

\begin{itemize}
\item \textsuperscript{11} Id. at P 19.
\item \textsuperscript{12} Id. at P 12.
\item \textsuperscript{13} March 24, 2011 EDC Comments on Agent’s March 21, 2011 Report, pp. 9-10 (available at http://www.bpu.state.nj.us/bpu/pdf/energy/EDCs.pdf).
\item \textsuperscript{14} Shanker Affidavit at P 28.
\end{itemize}
Second, FERC policy towards compensation of demand response providers participating in the energy markets also weighs against selecting combined cycle technology. As explained by Dr. Shanker, the policy of paying these resources “full LMP” when they pass a lax cost-benefits test – essentially giving them “double payments” since they also avoid paying any generation charges – will shift energy revenues away from generating plants.\(^\text{15}\) This trend will further deter investments in generating facilities based on energy market revenues.

Third, the current regulatory environment generally tends to favor lower capital cost investments. Constant attacks on RPM and efforts by the states – such as LCAPP – designed to suppress capacity and energy prices below competitive level translate into business risks.\(^\text{16}\) Investing in lower capital cost plants does not lower the risk but it does lower the financial exposure to the developer if the risk comes to fruition.

In these circumstances, decisions by developers to add capacity resources in the least capital-intensive manner available would appear to be an economically rationale response to current market conditions and the regulatory environment. As Dr. Shanker explains, there will always be special cases or “low hanging fruit” that may support particular investment decisions, including a decision to construct a new CC plant.\(^\text{17}\) Generally, however, to the extent that the construction of any generating resources can be justified at all from a financial standpoint under current market and regulatory conditions, Dr. Shanker’s analysis shows that the relevant factors favor the construction of lowest capital cost resources – namely CT technology. Similarly, the current conditions favor

\(^{15}\) Id. at P 4.
\(^{16}\) Id. at P 17.
\(^{17}\) Id. at P 20.
other types of capacity resources such as demand response resources and energy efficiency with even lower levels of capital cost commitments.

D. Conclusion

It is important that the Board consider the interrelatedness of these markets, and the results they achieve for consumers in planning a future course of action. Many statements were made at the June 17th hearing and in comments criticizing RPM for allegedly falling short of customer needs. PSEG Power’s experience has shown to the contrary, however, that the PJM markets have created appropriate price signals and thereby has resulted in market responses consistent with rational economic behavior. Further, PSEG Power submits that consumer have benefitted greatly from these market responses without being required to assume long-term market risks. Consumers have gained substantially from the PJM market construct and would be adversely affected if actions taken by the State of New Jersey interfered with the market’s operation.

Respectfully submitted,

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C Attached Service List (E-mail Only)
In the Matter of the Board’s Investigation of Capacity Procurement and Transmission Planning

NJ BPU Docket Number EO11050309

July 12, 2011

Affidavit of
Dr. Roy J. Shanker
1. My name is Roy J. Shanker. I am an independent consultant, with the majority of my practice focused on the electric utility industry. My business address is P.O. Box 60450, Potomac, Maryland 20859.

2. I have extensive experience with capacity market designs in ISO-NE, PJM and NYISO. I have previously offered testimony in Federal Energy Regulatory Commission (the “Commission”) proceedings related to capacity market design. I have also testified on a number of occasions regarding the exercise of buyer market power in organized RTO capacity markets. I recently submitted testimony to the Commission on three occasions in Docket Nos. ER10-787-000, EL10-50-000 and EL10-57-000 related to the exercise of buyer market power in capacity markets in ISO-NE. I similarly offered testimony before the Commission in Docket Nos. EL11-20 and ER11-2875, which addressed the Minimum Offer Price Rule (MOPR) in the PJM Tariff, which is intimately tied to this proceeding before the New Jersey Board of Public Utilities (the Board or BPU). I have also presented public comments and testimony before the New Jersey regarding the Long-Term Capacity Agreement Pilot Program (LCAPP).

I have also been a long-term, active participant on several committees and working groups addressing these issues in the NYISO and PJM markets and am part of the ongoing stakeholder process in PJM addressing potential modifications to the Reliability Pricing Model (RPM) which is PJM’s procurement system for assuring resource adequacy. In NYISO, I began working on the capacity market concepts prior to the start of the market; in PJM, I participated for at least eight years in the development of the current RPM markets.
My resume is attached as Appendix B.

3. While the BPU may be familiar with my positions regarding the inappropriateness of the LCAPP program and the need for a stronger MOPR, my comments here are relatively narrow. These comments should not be construed in any way to modify my previous positions. I understand that the BPU and other parties have expressed concerns not only regarding what they deem to be a lack of adequate investment in new generation in New Jersey but have also questioned why the capacity resources that have been added have consisted mainly of peaking units and demand response and not included more capital intensive and more efficient combined cycle generation alternatives. I have been asked by PSEG Power LLC and PSEG Energy Resources & Trade LLC (“PSEG Power”) to comment on certain elements of capacity acquisition and decision-making in a market environment such as PJM and how they relate to the choice of generation technology.

4. In looking only at this narrow issue, in the limited context of the current discussions in New Jersey, PJM and its RPM capacity market process, I reached one main conclusion based on several findings. While any individual decision to invest is very situation specific, under current circumstances, a general preference towards less capital intensive investments seems appropriate, in turn, rationally favoring the investment in peaking capacity or similar lower cost options such as repowering/improvement or demand response.
5. I came to this conclusion based on several observations. First, the basic paradigm of technology selection involving the trade-off between capital costs and associated higher fuel efficiency is still appropriate and appears to be driving decisions. Second, while the paradigm has, and should stay the same, empirical factors related to the execution of evaluations under this paradigm have changed materially with the move from cost based regulated recovery to market-like mechanisms for cost recovery. Third, in almost every instance, the empirical changes appear, at least for now, to favor lower capital risk and associated lower reliance on recovery from investments in efficiency (i.e. from earnings in the energy markets). These factors include, but are not limited to: i) the current system wide excess of capacity and associated low levels of realized income for CT’s and CC’s over the last 12 years; ii) the general transmission planning structure which as currently designed “leads” capacity decision making and reduces the recovery potential from the energy markets; iii) flaws in market design that tend to understate capacity value; iv) risk of regulatory intervention to devalue assets and the associated moral hazards created by such intervention; v) recent regulatory actions that have significantly eroded expectations of energy earnings to support more efficient and expensive capital generation, in particular the recent FERC Order 745.

6. In the following I discuss this conclusion and the related findings. As I stated this is a very complex decision process, so these comments should be seen more as a snapshot of major current factors than as being dispositive of the workings of the entire mechanism for investment in generation.
Background

7. The selection of the “right” generation technology is very complex decision process. Most of the technical theory relates to this type of decision-making in a regulated environment, where future forecasts of fuel costs and load shape were the primary unknowns. In this context a simplified version of the decision process was simply to find the lowest cost match of equipment in size and efficiency to future system needs. In general higher cost equipment was more efficient and had lower fuel/operating costs, so the basic problem revolved around the substitution of capital costs in terms of generation efficiency for fuel costs incurred in operation. If a generator was expected to operate frequently enough for the fuel savings to offset the increased capital costs, the more expensive generation was chosen. In the most simplistic view of the process, which was used historically, screening curves were created to evaluate alternative technologies. These curves looked at the average cost, capital and energy of each technology as a function of the expected level of operation or capacity factor. The dominant technology in each range of capacity factor was then considered in the broader context of the “best fit” to the system requirements.

8. For example it might be concluded that under existing capital and fuel costs a peaking unit would be the cheapest generation option between a capacity factor of zero and 25%, while a combined cycle would be cheaper between 25% and 55%, and above 55% a coal unit would be the best option. After such screens were applied, more sophisticated optimization models were then used to look at how such technologies best fit into the system requirements over time, considering when to build and what to build.
9. Understanding this trade off between efficiency in fuel conversion via higher capital costs and the expected cost of fuels is fundamental to understanding both the historic rate based environment and the current market-like situation in PJM. It is important not only to the choice of technology, but is also important for understanding what drives or should drive the basic functioning of the current capacity markets.

10. I have discussed this trade-off previously in terms of considerations of PJM’s overall market design. In electricity markets which include mandated reserves and place caps on energy prices or bids, marginal suppliers will not be able to recover their capital costs (inclusive of returns on and of capital) because prices do not reflect the full scarcity value of energy. This can be easily observed in cases in which there is a mandated surplus or targeted reserve level of generation which force an excess of supply virtually all of the time, and energy prices are set by the marginal clearing generator. Absent congestion, the marginal generator can only recover its variable energy costs and associated clearing price levels will never enable the marginal generator to recover its fixed costs. Bid caps associated with the mitigation of market power further reduce opportunities to recover fixed costs. This is the so-called “missing money” problem.

11. As illustrated by this example, the missing money equals the payments necessary to permit the marginal unit to recover its fixed capital costs. This not only drives the underlying logic of the capacity markets, but also helps explain the capital/energy trade-off for selection of the type of generating capacity that will be added. Recognizing that a new marginal unit may have lower operating costs than some existing generation, and that congestion may reflect additional payments to generators, the generalized solution is
to set the missing money level at the fixed capital costs of the marginal least capital
tensive unit net of additional revenues that may be received for the sale of energy and
ancillary services. This has been referred to as net cost of new entry or net CONE.

12. Consistent with economic theory, this value should always be based on the least
capital cost source of “pure” capacity available to meet adequacy requirements in the
market. That is, what is the cheapest way to add generation solely for adequacy assuming
operating levels at the margin? This is the appropriate characterization of what the
system planner or operator would economically be expected to do in order to meet an
increment of additional demand for adequacy/capacity. Effectively, and appropriately,
this determination focuses on the least cost action to assure additional reliability.

Further, from a theoretical perspective, when the generation system is in equilibrium, it
can be seen that this least cost value of pure capacity – in general the net CONE for a
combustion turbine – would also be expected to be net CONE for any other type of new
capacity resource added to the system. As discussed above, the generation addition that
has the lowest capital cost and highest energy cost would always be expected to under
recover its net CONE (absent some form of separate recovery for the “missing money”),
as it is the marginal resource and sets clearing prices.

13. One can see how this notion of need for capacity payments links up with the
capital/energy trade-off via example. Hypothetically assume that this shortfall, i.e., the
Net CT CONE, was the equivalent of $400 per MW day. Further, assume that it costs an
incremental $100 per MW day to convert a combustion turbine to a combined cycle.
Rationally, when there is an opportunity for a combustion turbine to earn $100.01 per MW day in additional energy margins by converting to a combined cycle, it should do so. However, by converting, the unit (and other similarly situated units) reduces potential margins by increasing the supply of lower cost energy, and in equilibrium (assuming the ability to continually add/convert small increments of capacity) such conversions would be expected to eliminate all available incremental margins above the cost of conversion, resulting in the converted unit remaining “short” the same missing money as the combustion turbine, *e.g.*, the $400 per MW day.

14. Thus the new generator should only build a CC unit to the extent that it expects that the increased energy margins (e.g. the $100/ MW day) will persist over a sufficient time to recover the higher capital costs. Obviously, even in this situation, there remains in a market environment, the need for a capacity payment at CT Net Cone, but this is exactly the same logic that has always driven the selection process for more capital intensive new generation.

15. The same logic regarding the capital/energy trade-off would also apply to converting a CC or a CT to a base load plant or building or new base load plant. In those cases, the investment is only undertaken when the conversion costs are offset by the increased energy margins. However, the same conclusion applies. Even after the conversions, at the margin and in equilibrium, all resources will still remain short the same amount of missing money.
Basic Differences Between Regulated and Market Decision-Making and Cost Recovery

16. In the historical cost based environment, the focus was on the “best” answer given uncertainty in construction, fuel cost, and load growth and shape forecasts. Typically evaluations were over a long-term horizon and implicitly assumed a single source of new entry. Similarly the cost of errors was small for the investor (the vertically integrated company) that in general was assured cost recovery for “prudent” actions, even if the information used and associated decisions were wrong. If after the fact, the forecast of fuel prices that might have justified the investment in a base load or intermediate unit was in error (e.g. coal prices were higher than expected), there were little or no consequences. This was particularly the case as once built, the more capital intensive rate based unit effectively converted its energy forecast into the bricks and mortar and steel of the new plant. A common expression I used to make regarding the process was that “IOU’s forecast errors were all buried in rate base”. The regulated investor was effectively insulated from both change of circumstances and most regulatory risk, assuming prudent decision-making.

17. In contrast, in a market environment, the consequences of errors or misjudgments regarding the capital energy trade-off, and the resulting plant selection decision are directly borne by the private investor. Thus not only must the investor bear the risk of forecasting the future energy and capacity market prices and the associated implied energy margin income based on fuel/load shape and other market parameter forecasts, but also must bear risk associated with any flaw in the underlying market design, change of that design, and regulatory risks that may influence both market design, the competitive
environment and virtually all market conditions. To the extent that any adverse events occur in any of these areas, private investors are at risk. This risk has to show up in their decision-making regarding both the level of capacity and energy prices, and the associated likelihood of capturing the needed operating margins to justify the investment. The more capital intensive the investment, the more the risk exposure incorporates not just “normal” exposure to changes in load shape, fuel prices and energy margins, but also the regulatory risk elements of the market design and regulatory intervention.

18. These differences in risk allocation in terms of the decision-making process do not mean that only one type of plant will or should be built, but what they do mean is that the calculus of the determination of what to build will yield different results from the fully regulated world. The issue is understanding the implications of the change in risk allocation, and making sure that all behavior in the process is appropriate and competitive.

19. In the specific circumstances we see today in PJM and New Jersey, there are a number of factors that tilt the risk equation squarely in favor of reduced capital exposure with respect to building new generation. I discuss each of them briefly in the following sections.

In General Margins Do Not Support Any New Entry.

20. The first observation that should be made is that in general prices simply do not support new entry today by any reasonable standard. While certainly there will always be exceptions and the proverbial “low hanging fruit,” prices since the start of the PJM
market have been well below any average level of recovery needed to support new entry. The entire rational for RPM was based on modeling which assumed that rational investors would see a stream of market prices for capacity, and only invest when their expectation would be that the forward path of prices over a business cycle would justify the investment. We simply haven’t seen that in PJM.

21. Since the start of the market over the last 12 years, the Independent Market Monitor has estimated that across PJM as a whole, a CT has only earned 46% of the average levelized costs needed to justify such an investment. During this period in New Jersey the level was 58% for PSEG, 64% for AECO and 59% for JCPL.1

22. Similar results have occurred for combined cycle units. For PJM as a whole only 61% of the average levelized 20 year cost has been recovered over the last 12 years. In New Jersey, AECO averaged 88%, JCPL 82% and PSEG 83%. In only one year did earnings exceed the levelized average.2

23. A direct corollary of these facts is, in general, there has been no need for new generation from a reliability standpoint. RPM’s demand curve is set to yield the net cost of new entry when reliability levels are at the targeted reserve margins plus 1%. When prices are below this level, which is what we are seeing, it means that supplies are adequate. Graphically, the relationship between the levelized Net CONE and realized

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2 Id., Tables 3-23 and 3-24.
3 This reflects real time pricing, and CC margins would be materially lower if based on day ahead energy prices, which are more consistent with general bidding behavior.
RPM prices shows exactly this result. These are also presented by the IMM in the State of the Market Report. If the combination of existing generation, energy efficiency and demand response are meeting reliability needs, it is hard to see any problem with a lack of new entry by generating plants and low prices. System wide the reserve margins are at approximately 20%, with uncleared capacity also existing in the markets that has not been sold in RPM.

24. Another set of analyses by the IMM also make these same points, but in the context of the type of conversion benefit that is needed to justify the movement from a CT to a CC unit. The 2010 20 year levelized fixed cost of a CT was estimated at $131,044 per MW year, and $175,250 for a CC, a difference of approximately $44,200 per MW year. In a very simplified fashion this means that a CC would have to earn an additional $44,200 per MW year in energy margins to justify the investment, and be expected to continue to earn at least that difference, on average, for 20 years.

25. The IMM also publishes information that allows an approximation of the potential earnings difference between the two types of units. If we assume approximately a 3,000 BTU advantage for the CC in heat rate, and gas costs of $5 per MMBTU, this yields a $15 per MWH spread in favor of the CC. If we assume an approximate cost of the CC at $40 per MWH, than this would result in an approximate cost for the CT of $55 per

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4 Id., Figures 3-5, 3-8.
5 Id., Figures 3-5, 3-8
6 Id., Table 3-20.
MWH.\textsuperscript{7} Using the IMM information on energy earnings as a function of the energy cost of a unit, a CC would have been expected to make approximately $37,000 a MW year more than a CT in 2010. I estimated the difference at approximately $19,700 for 2009.\textsuperscript{8} This is less than the cost differential for the units and suggests that even if the market could support new entry for a CT (which it does not), the energy margin differential would likely be insufficient to support the more expensive capital for the CC unit. Obviously these are average numbers, and the appropriate evaluation would be based on more precise cost data and site specific LMP’s, but the implications are clear, particularly when coupled with the previous observations regarding the overall insufficient level of net revenues.

\textbf{Transmission “ Leads” Generation In The Current PJM Planning Process}

26. For several reasons, new transmission leads generation in the current PJM transmission planning process. Transmission upgrades to meet reliability standards become mandatory and are ordered by PJM if generation within a constrained area appears to be inadequate. Given the poor coordination between the transmission planning process and the procurement of capacity resources in RPM, this assures that over time, both energy and capacity incomes associated with local scarcity will be reduced. Under this construct, reliance on energy income margins to support new entry becomes more risky as such premiums would be expected to be removed or reduced with the introduction of the mandated transmission.

\textsuperscript{7} These values are rough estimates reflecting $5 per MMBTU gas and a 7,000 BTU heat rate for the CC, a 10,000 BTU heat rate for the CT and $5 per MWH variable O&M, and ignoring other costs.

\textsuperscript{8} Id. Table 3-2. The information in the table shows the net income earned for a unit of differing operating costs. The values I computed reflected the difference in income between a $40 per MWH unit and a $55 per MWH unit. I interpolated the $50 and $60 values to derive the $55 estimate.
27. PJM establishes a locational capacity requirement for each LDA. The requirement reflects a targeted reliability standard. It includes the existing in-zone generation plus a required level of import capability, referred to as the Capacity Emergency Transfer Objective (“CETO”). The actual empirical transfer capability into an LDA is referred to as the Capacity Emergency Transfer Limit (“CETL”). Price separation can occur when (1) the CETL is less than the CETO, (2) access to cheaper resources in the rest of PJM is limited, and/or (3) more expensive in-zone resources are needed to meet zonal requirements.9

28. However, if PJM forecasts that CETL will be less than CETO, that constitutes an explicit reliability rule violation and must be addressed by mandatory transmission upgrades. This will occur whether the deficiency is caused by generator retirement, load growth, or change in overall transmission topology. This determination is reached in the context of the RTEP, which has a five-year planning horizon in comparison to the three-year forward horizon of RPM. Thus, given the mismatch between the RTEP and RPM timeframes, there cannot be a persistent transmission basis for price separation under RPM. Rather, the RTEP process anticipates and remedies transmission needs long before the RPM auctions are held. Mandatory transmission upgrades will be planned for and

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9 Imports into a zone can exceed the CETO and price separation still occur simply because the in zone resources are more expensive, not because there is a shortage of generation in the zone. Assume the average net cost of new entry is $175 per MW-day. Assume that the CETO is 1000 into an LDA, the local gen is 4000, and thus the reliability target for the zone is 5000 MW. Assume that CETL is 2000 or twice as high as the minimum requirement. Assume that at a level of 2000 MW of imports into the LDA the price was $100 per MW-day for the RTO, but at that price only 2000 MW of internal resources were available. Even though the CETL was twice the CETO, separation occurs and 1000 MW of additional internal resources that are priced more than $100 would be required to meet the local requirement (e.g., Assume there were 1000 MW offered between $100-125. Then the LDA clearing price would be $125 (ignoring the declining demand curve in this simple example)). There is no shortage in the zone, prices need not reach levels necessary to support new entry, and price separation occurs.
built to prevent such separation, regardless whether these would be the lowest cost or most efficient means of resolving a constraint. Prices for generation resources can reflect locational differences in construction or other local costs, but unless the current construct is changed to improve RTEP and RMP coordination (e.g. have a common five year lead time), there can be no expectation of a persistent locational premium due to transmission limitations.

29. Under the current construct, any transmission-based premium has to be expected to be reduced over time until the entire pool has met or is approaching a state in which capacity is in equilibrium. Transfer capability will continually be expanded on a leading basis to assure that sufficient deliverability exists within the rest of PJM to meet the mandatory CETO requirement. This bias towards transmission is real, and reflects material risk for generation development in constrained LDAs.

30. It is also important to note that the fact that prices have risen in an LDA above those in the rest of the market does not say anything about whether prices have risen high enough to support new entry for a generating plant. LDA prices may reflect a perceived premium to prices in the rest of PJM for any number of reasons. Perhaps the surplus in the LDA is smaller—CETL slightly greater than CETO—than the surplus prevailing in the rest of PJM. Or perhaps CETL is less than CETO but the requirement within the LDA is being met by existing resources with “to go” costs less than the cost of new entry. Regardless, the premium in and of itself does not constitute an incentive for new entry by a generating plant unless the absolute value of prices are expected to equal over an extended period at least the long run the average net cost of new entry. If prices in PJM
as a whole are $25/MW-day, and $100/MW-day in an LDA, it still does not make sense to build new generation if the necessary long-run average price has to be $150/MW-day. All that is established is that there are sufficient internal resources in the LDA, at a price less than or equal to $100/MW-day, to meet the target requirements. Further, it does not make sense to build a new generating plant if anticipated premiums will be reduced by mandatory transmission that further reduce premiums because reliability violations are not tolerated.

31. In combination, these conditions seem to be exactly what is being seen in New Jersey. Price separation is occurring, but at levels below the cost of new entry for a generating plant. Further, as discussed by many parties, the anticipation of several large new transmission projects including Susquehanna/Roseland, would be expected to both reduce capacity and energy pricing. In this situation, it obviously becomes riskier to invest in new generation in general, but in particular, to invest in a fashion that would rely strongly on margins earned out of the energy markets. This would again logically favor investments in combustion turbines versus combined cycles, all other factors being the same.

32. The bias in favor of transmission will continue unless and until substantial improvements are made in the process for coordinating transmission planning and the procurement of capacity resources under RPM.
Market Flaws

33. As a starting point, it must be recognized that the resiliency of the PJM RPM market design is limited by certain realities such that developers can be expected to assign significant risk to factors that interfere with its intended operation. The modeling of the RPM pricing mechanism was predicated on the possibility of allowing the market to go short, or for locality constraints to be temporarily violated to yield higher prices to offset periods of lower prices. As implemented, a variety of other market design elements prevent this from happening, thus removing an important class of potential price signals. Notably, the overlay of reliability back-stops removes most these higher pricing opportunities where above average prices would be expected to offset the below average new entry costs periods associated with surplus. Perceived flaws in the RPM design therefore both discourage new entry in general, and also create risks such that a developer would reasonably favor a less capital intensive alternative in making any decision to build new generating plants based solely on market revenues.

34. In fact, there are fundamental gaps in the PJM market design that systematically underpay supply and in turn may deter new entry. These flaws in design were further highlighted in recent presentations by the PJM Independent Market Monitor (“IMM”) who estimated that because PJM has a must offer requirement for 100% of existing supply, but only clears against 97.5% of forecast load, payments to suppliers were depressed by approximately $2 billion in the 2010 RPM auction. The IMM made

similar comments before the BPU in this proceeding. This type of implicit price suppression deters development of new generating plants generally and again makes it much riskier to choose more capital intensive resources making the choice of combustion turbines over combined cycles rational given all other factors the same.

**Regulatory Risk/Intervention**

35. Perhaps the biggest bias in favor of the selection of less capital intensive alternatives for capacity is the vulnerability of the market to regulatory intervention. While this can occur in many ways, two examples make the case very clear. First, the LCAPP process itself probably does as much or more to discourage capital investment in the PJM markets than any other of the factors addressed above. Estimates from the IMM put the impact of a 1,000 MW LCAPP procurement at approximately $1 billion, as a direct transfer from sellers to buyers unrelated to market needs or efficiency. Whether justified or not from the standpoint of the BPU, private capital has to consider risk like this when investing in long lived capital assets for the energy market. Again all other elements equal, one would expect a preference for lower capital exposure in supply new generation. Ultimately the presence of programs such as the LCAPP would be expected to eliminate any other competitive entry.

36. The second example of regulatory risk and action that has a major impact on the decision-making regarding choice of technology relates to the recent FERC Order 745.

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Under Order 745 the Commission has put in place a subsidy structure that effectively double pays demand response for reductions in load. The criteria for payment explicitly is based on the exercise of buyer market power, with payments only being made to individual participants when they can be justified by market savings to all participants via price suppression. The record in the proceeding is very clear that such “savings” did not reflect any efficiency gain, and only reflect a transfer of funds from suppliers to consumers. But another direct, though possibly unintended, result is that this transfer of funds also reflect the pool of money from energy rents that would support the greater energy efficiency related costs of moving from a combustion turbine to a combined cycle. The flatter the load curve due to the Order 745 subsidies, the less likely there will be sufficient energy rents to justify greater capital investments in base load generation. In the short run this has to be reflected again as a form or risk that would favor any new generation selecting combustion turbine over combined cycle configurations. At minimum this also removes much of the anticipated energy rents associated with existing units and diminishes the incentives to uprate/upgrade existing units.

**Conclusion**

37. A variety of factors have combined to result in a rational market decision process that currently would favor either no new construction at all, or if generation was built, the lowest possible capital costs and associated dependence on margins earned from the energy market. The overall market is in surplus; historic prices for the last 12 years have been materially lower than the average needed to support new entry; the existing RPM structure has several biases that make higher capital investment risky; general market design rules regarding transmission tend to reduce the potential for earning energy
margins; and both this Board and the FERC have adopted policies that further erode current energy and capacity revenues.
Table 3-2

Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2010

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<td>$2,248</td>
<td>$28,260</td>
</tr>
<tr>
<td>2003</td>
<td>$2,763</td>
<td>$5,554</td>
<td>$0</td>
<td>$0</td>
<td>$2,248</td>
<td>$10,566</td>
</tr>
<tr>
<td>2004</td>
<td>$919</td>
<td>$5,376</td>
<td>$0</td>
<td>$0</td>
<td>$2,248</td>
<td>$8,543</td>
</tr>
<tr>
<td>2005</td>
<td>$6,141</td>
<td>$2,048</td>
<td>$0</td>
<td>$0</td>
<td>$2,248</td>
<td>$10,437</td>
</tr>
<tr>
<td>2006</td>
<td>$10,996</td>
<td>$1,758</td>
<td>$0</td>
<td>$0</td>
<td>$2,194</td>
<td>$14,948</td>
</tr>
<tr>
<td>2007</td>
<td>$17,933</td>
<td>$28,442</td>
<td>$0</td>
<td>$0</td>
<td>$2,154</td>
<td>$48,529</td>
</tr>
<tr>
<td>2008</td>
<td>$12,442</td>
<td>$35,691</td>
<td>$0</td>
<td>$0</td>
<td>$2,398</td>
<td>$50,532</td>
</tr>
<tr>
<td>2009</td>
<td>$5,113</td>
<td>$48,441</td>
<td>$0</td>
<td>$0</td>
<td>$2,384</td>
<td>$55,939</td>
</tr>
<tr>
<td>2010</td>
<td>$36,925</td>
<td>$55,309</td>
<td>$0</td>
<td>$0</td>
<td>$2,384</td>
<td>$94,619</td>
</tr>
</tbody>
</table>
Table 3-20

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>$72,207</td>
<td>$80,315</td>
<td>$90,656</td>
<td>$123,640</td>
<td>$128,705</td>
<td>$131,044</td>
</tr>
<tr>
<td>CC</td>
<td>$83,549</td>
<td>$99,230</td>
<td>$143,600</td>
<td>$171,361</td>
<td>$173,174</td>
<td>$175,250</td>
</tr>
<tr>
<td>CP</td>
<td>$208,247</td>
<td>$267,792</td>
<td>$359,750</td>
<td>$492,780</td>
<td>$446,550</td>
<td>$465,455</td>
</tr>
</tbody>
</table>
Table 3-22

Table 3-22 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Net Revenue</td>
<td>Levelized Cost</td>
</tr>
<tr>
<td>AECO</td>
<td>$111,89</td>
<td>$131,044</td>
<td>85%</td>
<td>$56,729</td>
<td>$88,317</td>
</tr>
<tr>
<td>AEP</td>
<td>$61,37</td>
<td>$131,044</td>
<td>47%</td>
<td>$27,562</td>
<td>$88,317</td>
</tr>
<tr>
<td>AP</td>
<td>$95,61</td>
<td>$131,044</td>
<td>73%</td>
<td>$35,134</td>
<td>$88,317</td>
</tr>
<tr>
<td>BGE</td>
<td>$130,47</td>
<td>$131,044</td>
<td>100%</td>
<td>$59,223</td>
<td>$88,317</td>
</tr>
<tr>
<td>ComEd</td>
<td>$59,08</td>
<td>$131,044</td>
<td>45%</td>
<td>$28,529</td>
<td>$88,317</td>
</tr>
<tr>
<td>DAY</td>
<td>$60,78</td>
<td>$131,044</td>
<td>46%</td>
<td>$27,408</td>
<td>$88,317</td>
</tr>
<tr>
<td>DLCO</td>
<td>$67,53</td>
<td>$131,044</td>
<td>52%</td>
<td>$39,371</td>
<td>$88,317</td>
</tr>
<tr>
<td>Dominion</td>
<td>$99,38</td>
<td>$131,044</td>
<td>76%</td>
<td>$50,636</td>
<td>$88,317</td>
</tr>
<tr>
<td>DPL</td>
<td>$10,96</td>
<td>$131,044</td>
<td>85%</td>
<td>$53,790</td>
<td>$88,317</td>
</tr>
<tr>
<td>JCPL</td>
<td>$107,11</td>
<td>$131,044</td>
<td>82%</td>
<td>$52,346</td>
<td>$88,317</td>
</tr>
<tr>
<td>Met-Ed</td>
<td>$107,48</td>
<td>$131,044</td>
<td>82%</td>
<td>$44,601</td>
<td>$88,317</td>
</tr>
<tr>
<td>PECO</td>
<td>$104,50</td>
<td>$131,044</td>
<td>80%</td>
<td>$49,814</td>
<td>$88,317</td>
</tr>
<tr>
<td>PENELEC</td>
<td>$84,83</td>
<td>$131,044</td>
<td>65%</td>
<td>$34,930</td>
<td>$88,317</td>
</tr>
<tr>
<td>Pepco</td>
<td>$139,43</td>
<td>$131,044</td>
<td>106%</td>
<td>$62,102</td>
<td>$88,317</td>
</tr>
<tr>
<td>PPL</td>
<td>$101,10</td>
<td>$131,044</td>
<td>77%</td>
<td>$41,247</td>
<td>$88,317</td>
</tr>
<tr>
<td>PSEG</td>
<td>$104,84</td>
<td>$131,044</td>
<td>80%</td>
<td>$50,958</td>
<td>$88,317</td>
</tr>
<tr>
<td>RECO</td>
<td>$99,90</td>
<td>$131,044</td>
<td>76%</td>
<td>$47,394</td>
<td>$88,317</td>
</tr>
<tr>
<td>PJM</td>
<td>$94,61</td>
<td>$131,044</td>
<td>72%</td>
<td>$40,943</td>
<td>$88,317</td>
</tr>
</tbody>
</table>
Table 3-23  CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

<table>
<thead>
<tr>
<th></th>
<th>20 Year Levelized Fixed Cost</th>
<th>Economic Dispatch Net Revenue</th>
<th>Economic Dispatch Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>$93,549</td>
<td>$100,700</td>
<td>108%</td>
</tr>
<tr>
<td>2000</td>
<td>$93,549</td>
<td>$47,592</td>
<td>51%</td>
</tr>
<tr>
<td>2001</td>
<td>$93,549</td>
<td>$86,670</td>
<td>93%</td>
</tr>
<tr>
<td>2002</td>
<td>$93,549</td>
<td>$52,272</td>
<td>56%</td>
</tr>
<tr>
<td>2003</td>
<td>$93,549</td>
<td>$35,591</td>
<td>38%</td>
</tr>
<tr>
<td>2004</td>
<td>$93,549</td>
<td>$35,785</td>
<td>38%</td>
</tr>
<tr>
<td>2005</td>
<td>$93,549</td>
<td>$40,817</td>
<td>44%</td>
</tr>
<tr>
<td>2006</td>
<td>$99,230</td>
<td>$49,529</td>
<td>50%</td>
</tr>
<tr>
<td>2007</td>
<td>$143,600</td>
<td>$100,809</td>
<td>70%</td>
</tr>
<tr>
<td>2008</td>
<td>$171,361</td>
<td>$103,928</td>
<td>61%</td>
</tr>
<tr>
<td>2009</td>
<td>$173,174</td>
<td>$81,376</td>
<td>47%</td>
</tr>
<tr>
<td>2010</td>
<td>$175,250</td>
<td>$130,061</td>
<td>74%</td>
</tr>
<tr>
<td>Avg.</td>
<td>$118,122</td>
<td>$72,094</td>
<td>61%</td>
</tr>
</tbody>
</table>
Table 3-24  CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

<table>
<thead>
<tr>
<th></th>
<th>2010 Net Revenue</th>
<th>20 Year levelized Cost</th>
<th>Percent Recovered</th>
<th>2010 Net Revenue</th>
<th>20 Year Levelized Cost</th>
<th>Percent Recovered</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECO</td>
<td>$175,900</td>
<td>$175,250</td>
<td>100%</td>
<td>$103,506</td>
<td>$118,122</td>
<td>88%</td>
</tr>
<tr>
<td>AEP</td>
<td>$98,280</td>
<td>$175,250</td>
<td>56%</td>
<td>$51,940</td>
<td>$118,122</td>
<td>44%</td>
</tr>
<tr>
<td>AP</td>
<td>$152,516</td>
<td>$175,250</td>
<td>87%</td>
<td>$73,565</td>
<td>$118,122</td>
<td>62%</td>
</tr>
<tr>
<td>BGE</td>
<td>$199,355</td>
<td>$175,250</td>
<td>114%</td>
<td>$103,738</td>
<td>$118,122</td>
<td>88%</td>
</tr>
<tr>
<td>ConEd</td>
<td>$87,686</td>
<td>$175,250</td>
<td>50%</td>
<td>$54,767</td>
<td>$118,122</td>
<td>46%</td>
</tr>
<tr>
<td>DAY</td>
<td>$97,600</td>
<td>$175,250</td>
<td>56%</td>
<td>$51,510</td>
<td>$118,122</td>
<td>44%</td>
</tr>
<tr>
<td>DLCO</td>
<td>$101,473</td>
<td>$175,250</td>
<td>58%</td>
<td>$80,625</td>
<td>$118,122</td>
<td>68%</td>
</tr>
<tr>
<td>Dominion</td>
<td>$162,324</td>
<td>$175,250</td>
<td>93%</td>
<td>$95,967</td>
<td>$118,122</td>
<td>81%</td>
</tr>
<tr>
<td>DPL</td>
<td>$175,605</td>
<td>$175,250</td>
<td>100%</td>
<td>$95,074</td>
<td>$118,122</td>
<td>80%</td>
</tr>
<tr>
<td>JCPL</td>
<td>$170,893</td>
<td>$175,250</td>
<td>98%</td>
<td>$96,902</td>
<td>$118,122</td>
<td>82%</td>
</tr>
<tr>
<td>Met-Ed</td>
<td>$167,178</td>
<td>$175,250</td>
<td>95%</td>
<td>$83,806</td>
<td>$118,122</td>
<td>71%</td>
</tr>
<tr>
<td>PECO</td>
<td>$164,909</td>
<td>$175,250</td>
<td>94%</td>
<td>$90,268</td>
<td>$118,122</td>
<td>76%</td>
</tr>
<tr>
<td>PENELEC</td>
<td>$134,761</td>
<td>$175,250</td>
<td>77%</td>
<td>$64,538</td>
<td>$118,122</td>
<td>55%</td>
</tr>
<tr>
<td>Pepco</td>
<td>$214,688</td>
<td>$175,250</td>
<td>123%</td>
<td>$108,477</td>
<td>$118,122</td>
<td>92%</td>
</tr>
<tr>
<td>PPL</td>
<td>$157,856</td>
<td>$175,250</td>
<td>90%</td>
<td>$78,033</td>
<td>$118,122</td>
<td>66%</td>
</tr>
<tr>
<td>PSEG</td>
<td>$168,625</td>
<td>$175,250</td>
<td>96%</td>
<td>$98,551</td>
<td>$118,122</td>
<td>83%</td>
</tr>
<tr>
<td>RECO</td>
<td>$158,836</td>
<td>$175,250</td>
<td>91%</td>
<td>$101,984</td>
<td>$118,122</td>
<td>86%</td>
</tr>
<tr>
<td>PJM</td>
<td>$149,912</td>
<td>$175,250</td>
<td>86%</td>
<td>$73,748</td>
<td>$118,122</td>
<td>62%</td>
</tr>
</tbody>
</table>
Table 3-25 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2010

<table>
<thead>
<tr>
<th>Year</th>
<th>20-Year Levelized Fixed Costs</th>
<th>Economic Dispatch Net Revenue</th>
<th>Economic Dispatch Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>$208,247</td>
<td>$118,022</td>
<td>57%</td>
</tr>
<tr>
<td>2000</td>
<td>$208,247</td>
<td>$134,564</td>
<td>65%</td>
</tr>
<tr>
<td>2001</td>
<td>$208,247</td>
<td>$129,271</td>
<td>62%</td>
</tr>
<tr>
<td>2002</td>
<td>$208,247</td>
<td>$112,131</td>
<td>54%</td>
</tr>
<tr>
<td>2003</td>
<td>$208,247</td>
<td>$169,509</td>
<td>81%</td>
</tr>
<tr>
<td>2004</td>
<td>$208,247</td>
<td>$133,124</td>
<td>64%</td>
</tr>
<tr>
<td>2005</td>
<td>$208,247</td>
<td>$228,430</td>
<td>110%</td>
</tr>
<tr>
<td>2006</td>
<td>$267,792</td>
<td>$182,461</td>
<td>68%</td>
</tr>
<tr>
<td>2007</td>
<td>$359,750</td>
<td>$277,284</td>
<td>77%</td>
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<tr>
<td>2008</td>
<td>$492,780</td>
<td>$218,144</td>
<td>44%</td>
</tr>
<tr>
<td>2009</td>
<td>$446,550</td>
<td>$94,968</td>
<td>21%</td>
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<tr>
<td>2010</td>
<td>$465,455</td>
<td>$185,644</td>
<td>40%</td>
</tr>
<tr>
<td>Avg</td>
<td>$290,838</td>
<td>$165,296</td>
<td>57%</td>
</tr>
</tbody>
</table>
Figure 3-5

Figure 3-5  New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010
Figure 3-8

Figure 3-8  New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MWh-year): Calendar years 1999 to 2010
APPENDIX B

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present
Independent Consultant
P.O. Box 60450
Potomac MD 20854

Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.

1979-81
Hagler, Bailly & Company
2301 M Street, N.W.
Washington, D.C.

Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.

1976-79
1901 L Street, N.W.
Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2011


Federal Energy Regulatory Commission Docket Nos. ER04-449. Affidavit and supplemental statement on behalf of New York Suppliers addressing the appropriate criteria for the establishment of a new capacity zone in the NYISO markets.

2010

New Jersey State Assembly and Senate. Statements on behalf of the Competitive Supplier Coalition addressing market power and reliability impacts of proposed legislation, Assembly Bill 3442 and Senate Bill 2381


Federal Energy Regulatory Commission. Docket ER11-2059 Affidavit on behalf of First Energy Services Company addressing deficiencies and
computational problems in the proposed “exit charges” for transmission owners leaving the MISO RTO related to long term transmission rights.


Federal Energy Regulatory Commission Docket No. ER09-1063-004. Testimony on behalf of the PJM Power Providers Group (P3) regarding the proposed shortage pricing mechanism to be implemented in the PJM energy market. Reply comments related to a similar proposal by the independent market monitor.

PJM RTO. Statement regarding the impact of the exercise of buyer market power in the PJM RPM/Capacity market. Panel discussant on the issue at the associated Long Term Capacity Market Issues Symposium.


Federal Energy Regulatory Commission Docket No. RM10-17-000, Affidavit on my behalf regarding inconsistent representations made
between filings in this docket and contemporaneous materials presented in the PJM stakeholder process.

2009


American Arbitration Association, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.


Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.


Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties’ filings.

2008

Pennsylvania Public Service Commission. En Banc Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.


Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission’s ANOPR on Competition.

FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006
United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

FERC Docket No. ER06-1474-000, FERC. Testimony on behalf of the PSEG Companies regarding the PJM proposed new policy for including “market efficiency” transmission upgrades in the regional transmission expansion plan.

FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.


Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004


Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.


Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.
American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cineregy Solutions regarding an energy services agreement related to a cogeneration facility.

Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.


Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.


Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

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Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO’s to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacity credits.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

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Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational
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Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.


New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.
Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an application for a certificate for new generation facilities.

Federal Energy Regulatory Commission. Analyses related to a number of docket reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

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United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

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Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New York Power Pool and the implementation of locational marginal cost pricing.

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PJM Power Pool and the implementation of locational marginal cost pricing.

Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

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Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.


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New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

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1995


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New York Public Service Commission, Case 95-E-0172, Testimony on the correct design of standby, maintenance and supplemental service rates for qualifying facilities.

Florida Public Service Commission, Docket No. 941101-EQ. Testimony related to the proper analyses and procedures related to the curtailment of purchases from Qualifying Facilities under Florida and FERC regulations.

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American Arbitration Association, Case Number 11 Y198 00352 94 Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a NUG facility.

United States District Court, Middle District Florida, Case No. 94-303 Civ-Orl-18. Analyses related to contract pricing interpretation other
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New York Public Service Commission Case 93-E-0272, Testimony regarding PURPA policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

Circuit Court for the City of Richmond. Case Number LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

New York Public Service Commission, Case 93-E-0958 Analyses of Stand-by, Supplementary and Maintenance Rates of Niagara Mohawk Power Corporation for Qualifying Facilities.


American Arbitration Association, Case 55-198-0198-93, Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power generation facility.

1993

U.S. District Court, Southern District of New York Case 92 Civ 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

State Corporation Commission, Virginia. Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.


Circuit Court of the Eleventh Judicial Circuit, Dade County, Florida. Case No. 92-08605-CA-06. Analyses related to compliance with electric and thermal energy purchase agreements. Damage analyses and testimony.

Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.


State of New York Public Service Commission. Cases 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.


1992

Pennsylvania Public Service Commission. Dockets No. P-870235,C-913318,P-910515,C-913764. Testimony regarding the calculation of avoided costs for GPU/Penelec.

Public Service Commission of Maryland. Case No. 8413,8346. Testimony on the appropriate avoided costs for Pepco, and appropriate procedures for contract negotiation.

1991

Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.


State Corporation Commission, Virginia. Case No. PUE910048
Testimony on proper data and modeling procedures to be used in the
evaluation of the annual Virginia Power fuel factor.

Evaluation of the differential revenue requirements method for the
calculation of avoided costs.

Public Service Commission of Maryland. Case Number 8241 Phase II.
Testimony related to the proper determination of avoided costs for
Baltimore Gas and Electric.

Public Service Commission of Maryland. Case Number 8315. Evaluation
of the system expansion planning methodology and the associated impacts
on marginal costs and rate design, PEPCO.

1990

Public Utility Commission, State of California, Application 90-12-064.
Analyses related to the contractual obligations between San Diego Gas
and Electric and a proposed QF.

Montana Public Service Commission. Docket 90.1.1 Testimony and
analyses related to natural gas transportation, services and rates.

Testimony on the calculation of full avoided costs via the differential
revenue requirements methodology.

District of Columbia Public Service Commission. Formal Case 834 Phase
II. Analyses and development of demand side management programs and
least cost planning for Washington Gas Light.

State Corporation Commission, Virginia. Case No. PUE890076. Analyses
related to administratively set avoided costs. Determination of optimal
expansion plans for Virginia Power.

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PEPCO.


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1989

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Virginia State Corporation Commission. Case Number PUE890007. Testimony relating to the proper determination of avoided costs to the certification evaluation of new generation facilities.


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1988

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Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.


Oklahoma Corporation Commission. Cause Pud No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

Florida Public Service Commission. Docket No. 8700197-EI. Testimony on the methodology for establishing non-firm load service levels.


1987


District of Columbia Public Service Commission. Formal Case No. 834 Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.


1986


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Public Utility Commission, New Hampshire Docket No. DR-86-41. Testimony on pricing and contract terms for power purchase agreement between utility and QFs. (Settlement Negotiations)

Florida Public Service Commission, Docket No. 850673-EU. Testimony on generic issues related to the design of standby rates for qualifying facilities.

Virginia State Corporation Commission. Case No. 860024. Generic hearing on natural gas transportation rate design and tariff terms and conditions.


Bonneville Power Administration. Case No. VI86. Testimony on the proposed Variable Industrial Power Rate for Aluminum Smelters.

Virginia Power. Case No. PUE860011. Testimony on the proper ex post facto valuation of avoided power costs for qualifying facilities.

Florida Public Service Commission. Docket No. 850004 EU. Testimony on proper analytic procedures for developing a statewide generation expansion plan and associated avoided unit.

1985

Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.


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Assist in the development of testimony for industrial natural gas transportation rates.

Oklahoma Gas and Electric. Cause 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.


Virginia Electric and Power Company. General Rate application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.


New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

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Northern Virginia Electric Cooperative. Case No.
PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

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Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

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PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Board's
Investigation of Capacity
Procurement and Transmission
Planning

NJ BPU Docket Number EO11050309

AFFIDAVIT OF
ROY J. SHANKER PH.D.

I, the undersigned, depose and state that the contents of the foregoing Affidavit are true, correct, accurate and complete, to the best of my knowledge, information and belief.

[Signature]
Roy J. Shanker 7/12/11