BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 7-R

Rebuttal Testimony of Scott T. Jones, Ph.D.

INTRODUCTION

Q: Would you please state your name?

A: My name is Scott T. Jones.

Q: Dr. Jones, have you previously presented testimony in this proceeding?

A: Yes. I presented direct testimony and exhibits on behalf of Pennsylvania Power and Light Company (PP&L), Statement No. 7 and Exhibits STJ-1 through 8 filed with the Pennsylvania Public Utility Commission (Commission or PAPUC) on April 1, 1997.

Q: What was the focus of your prepared direct testimony?

A: My testimony provided a long-term forecast of the market-clearing prices for energy and capacity following the introduction of wholesale and retail competition in PJM and Pennsylvania. My task included producing forecasts for two key variables that underlie the estimate of market-clearing prices for energy and capacity: annual fuel price escalators and inflation rates. I would note that these are two of the most important variables about which the Commission needs to make a decision in order to arrive at a calculation of stranded cost.

In addition to the market-clearing prices for energy and capacity, I provided PP&L's Mr. Schadt with the data from EGEAS necessary to produce the plant-specific annual revenue estimates for his stranded cost calculation.

Q: Please describe the purpose of your rebuttal testimony.

A: The purpose of my testimony is to rebut the direct testimony and exhibits of Randall J. Falkenberg on behalf of the PP&L Industrial Customer Alliance (PPLICA), the direct testimony of Donald E. Johnstone on behalf of Mid-Atlantic Power Supply Association, the direct testimony and exhibits of Robert D. Knecht on behalf of the Office of Small Business Advocate (OSBA), the prepared testimony and exhibits of David Schoengold on behalf of the Environmentalists, and the direct testimony of Douglas C. Smith on behalf of the Office of Consumer Advocate (OCA) regarding the formation of market prices in a competitive wholesale and retail generation market. I will also provide rebuttal testimony regarding the various market power issues raised in the direct testimony of

Bruce Edward Biewald on behalf of the Environmentalists, in the direct testimony of Douglas C. Smith on behalf of the Office of Consumer Advocate, by Mr. Johnstone for Mid Atlantic Power Supply Association and by Professor John W. Mayo on behalf of Enron Power Marketing, Inc.

SCOPE OF THE TESTIMONY

Q: Can you provide some idea of the scope of your rebuttal testimony?

A: Yes. I will concentrate my testimony on four central themes that pervade the intervenors' testimony:

- Intervenors ignore the full impact of competitive pressures that will be brought to bear on the generation market.
- Intervenors unfortunately sponsored fuel forecasts that have since undergone a major revision just months ago by the organizations that created the data. Hence, intervenors experts' fuel forecasts, for this and other reasons, certainly overstate future fuel prices, lessening the validity of any criticism of my fuel prices as too low.

- Intervenors rely on these same forecasting organizations for forecasts of inflation whose past forecasts, when compared to price changes over the last decade bear little correspondence to those recorded changes in inflation.
- Intervenors' contention that PP&L will possess vertical or horizontal market power is disputed by the facts and by the findings of the Federal Energy Regulatory Commission.

In addition, based on my particular expertise in fuel market analysis and fuel price forecasting, I will provide the Commission with a perspective on the record in this proceeding regarding forecasts of fuel prices. Since a discussion of this evidence on fuel prices is an important building block for discussing the other themes, I will start there.

A Perspective on the Fuel Price Forecasts Filed to Date in this Proceeding

Q: Dr. Jones, why is it important to comment about the fuel price forecasts as the first issue to discuss in electricity generation market price formation?

A: In the PJM region, the single most important driver of electricity price in a competitive generation market – especially in the short run, but also in the long run – is fuel prices. As a result, the fuel price forecast the Commission implicitly or explicitly adopts in this proceeding will have the single largest impact on the resulting market-clearing energy price, no matter what model is used to produce the forecasted competitive price for energy. In turn, the market-clearing energy price will have the single largest impact on the utility's estimated stranded cost.

The record in this proceeding is replete with fuel price information. To date, experts for the utilities have put forth 6 long-term fuel price forecasts (PP&L's, Met-Ed/Penelec's, plus 4 for PECO). The intervenors have put forth two forecasts for the years 1999-2015. Thus far, the ranges of experts' annual fuel price changes are extreme: they range from estimates of shrinking nominal prices through 1999 to increasing nominal prices at a rate of 7%/year after 1999.[1] Most importantly for the Commission, all but two of the experts' long-term forecasts have been changed by

[1] The sources cited for intervenors' forecasts include: Energy Information Administration, *Annual Energy Outlook 1997*, Washington D.C.: EIA Office of Integrated Analysis and Forecasting, U.S. DOE, December 1996. Energy Information Administration, Third Quarter 1997, *Short-Term Energy Outlook*, Washington D.C.: EIA Office of Integrated Analysis and Forecasting, U.S. DOE, July 7, 1997. DRI/McGraw Hill, *World Energy Service U.S. Outlook*, Spring 1997. DRI/McGraw Hill, *World Energy Service U.S. Outlook*, Fall/Winter 1996-97.

the witnesses and/or changed by the agencies relied upon by the experts.

If the changes had been minor forecast revisions, the Commission might simply accept the changes as routine, but the proposed update is so drastic as to change the *direction* of the forecast, not just the rate of increase. Worse, these changes were made to 20-year forecasts, not just short-term predictions, where major shifts in opinion might be expected. If I were independently advising the Commission and Staff, I would be concerned and asking a lot of questions about what was going on.

Q: Can you offer some insight and advice?

A: Yes. As to why the forecasts changed, I answer that elsewhere in my rebuttal testimony. As to what the Commission should do at this point, I have the following advice.

First, recognize that the fuel prices used in the forecasts of market-clearing prices consist of two parts: a real rate of change in fuel prices and inflation.

Second, for the two most-disputed fuel prices in this proceeding, e.g., price changes for oil and gas, the Commission should let its selection of a forecast be heavily influenced by the past, unless the Commission becomes convinced that a departure from historical trends is justified.

In that regard, the past contains two helpful facts:

- Oil and natural gas prices move together because they compete for many of the same customers in the marketplace.
- The trend in (real) oil prices is flat.

Third, choose an inflation rate that makes sense both in terms of historical precedent and with regard to *real* changes in the price of fuels. This simply requires that the Commission select a rate of inflation separate from, but with one eye on, what it thinks fuel prices will do. For example, as I will show, history tells us there is a very close correspondence in the rate of change in energy prices and the rate of change in inflation. So, if the Commission accepts that the price of oil and gas ought to be flat in *real* terms, like historical trends indicate, then the rate of inflation ought to be constant, too.

The Intervenors' Claims for Higher Energy and Capacity Prices Can Be Reduced to Four Themes

Q: Please summarize the four central themes that pervade the testimony of intervenors' witnesses.

A: First, the intervenors demonstrate a propensity to ignore, or otherwise misrepresent, the degree and extent of the competitive pressure that consumer choice will bring to bear on the formation of market prices for both energy and capacity.

Second, the intervenors' criticisms of my fuel price forecasts are both without merit and, when adjusted for the errors in method or application, nearly identical to my view of the market for utility fuel price escalation. In comparing intervenors' forecasts to my own, their forecasts suffer from inconsistent assumptions regarding the behavior of competitive markets for fuels. In some instances, they selectively adopt fuel price forecasts that were known to be out of date prior to their preparation of testimony in order to obtain the result that they support. Also, intervenors embrace forecasts that for years have been greeted with skepticism and considered seriously flawed by the energy industry because of their lack of consistency with known facts, i.e., the models tend to produce forecasts that are distinctly biased toward high, ever-increasing energy prices. Trends of this nature have no precedent in actual energy price behavior.

Third, in response to the intervenors' arguments that my use of a 2.5% rate of inflation is misplaced and inappropriate given the forecasts of others, I will show that:

- the Commission should require experts to report their forecasts of inflation-adjusted changes in fuel prices. This way the experts have to explain fuel market fundamentals aside from inflationary pressures in the overall economy;
- there are compelling reasons to reject intervenors' use of a higher inflation forecast;
- it makes sense for the Commission to adopt a reasonable, fixed inflation forecast for the purpose of market price and stranded cost calculation.

Fourth, intervenors' allegation that PP&L possesses market power is contradicted by the intent of the Electricity Generation Customer Choice and Competition Act (Act), and by the findings in the Federal Energy Regulatory Commission's (FERC) Order of July 17,1997 in Docket No. ER97-3055-000, in which PP&L was found to lack market power for purposes of charging wholesale market-based rates.

Intervenors Raise a Series of Technical Issues that Have No Merit

Q: Will you provide rebuttal testimony on other topics?

A: Yes. The intervenors raise a series of what I have chosen to call "technical and data issues" that I will show are theoretically and computationally incorrect as well as empirically unimportant.

Q: What do you mean by empirically unimportant?

A: These are issues that they spend a considerable amount of time and effort raising, alleging that I was wrong for not recognizing their importance, and criticizing their absence in my market price analysis. I will show that, in reality, these contentions are without merit, or simply wrong in that they fail to significantly impact market-clearing prices or they actually *depress* forecasted market prices further when properly included in the analysis.

Q: What are some of these technical and data issues that are raised by the intervenors and command your attention to rebut?

A: Intervenors raise what can be called a "heat rate" issue, alleging that the way PP&L's dispatch model (EGEAS) selects which blocks of capacity to dispatch at any point in time created a systematic understatement in PP&L's estimate of market-clearing prices.

Secondly, intervenors allege that the market-clearing capacity prices shown in my Exhibit STJ-8 are insufficient to stimulate investors to begin to install new generation capacity in the form of combustion turbine units (CTs) or combined cycle units (CCs).

Third, intervenors argue that PP&L did not properly account for the revenue that generators would earn from certain ancillary services in forming its estimate of future market-clearing prices.

Fourth, intervenors are critical of PP&L's use of a probabilistic dispatch model when generating estimates of market-clearing prices for energy. Intervenors argue that while the dispatch price will be correct on average, a probabilistic model will understate revenue compared to other simulation models.

Fifth, intervenors argue that PP&L ought to have added costs for NO_x allowances/abatement equipment when formulating market-clearing prices even though intervenors have not offered a method of their own for estimating these costs.

Sixth, intervenors argue that PP&L should have included administration and general (A&G) costs in its market price analysis and suggest a method for incorporating those costs.

Seventh, intervenors' experts state that PP&L's use of a 90% capacity factor for incumbent NUGs is too high.

Finally, intervenors contend that PP&L's experts assume unreasonable plant retirement data when formulating expected market-clearing prices.

Intervenors Have Gotten It Wrong When Introducing These Technical Issues

Q: Briefly, can you give the Commission some idea of what the intervenors got wrong with regard to some of these technical or data issues and how they affect your testimony in this matter?

A: Yes. In this section, I will concentrate on the significant errors in three of the eight technical issues. All eight issues are discussed later in my rebuttal testimony.

Possibly the most visible, allegedly damaging criticism intervenors raise is what I have called the "heat rate" issue. This relatively complex issue centers on the contention that PP&L has created a systematic downward bias in its market-clearing price estimates by relying on the theoretically sound concept that competition would drive prices toward incremental costs of generation for the last unit dispatched. PPLICA's witness, Mr. Falkenberg, argues that "suppliers will change their definition of incremental costs to include <u>all</u> variable costs" [at 18, 1-2], because the average cost of the first block of capacity dispatched from non-base load units exceeds the incremental cost of generation from that block. Mr. Falkenberg concludes, "the bid procedure will have to broaden the current definition of incremental costs to include all types of variable costs." [at 18, 7-8]. The intervenors want to imply that the average heat rate of generation for units dispatched in PJM exceeds the incremental heat rate, so that no generator would knowingly bid his marginal heat rate into the market for fear of losing money on an on-going basis. Mr. Falkenberg goes on to recommend that the Commission recognize that PP&L's market-clearing prices systematically understate the real prices that will prevail in the competitive market and that the Commission should adopt a single heat rate for each unit equal to the average full load heat rate.

Whether Mr. Falkenberg's allegation has merit is an empirical question. The only way the Commission could know would be to require PP&L to re-run EGEAS using a single, average full-load heat rate in place of the multi-block heat rates EGEAS uses to replicate the way the system is actually dispatched. In that way, the Commission could see for itself whether there was a systematic understatement in the market-clearing prices sponsored by PP&L, and subsequently, an overstatement in its stranded cost estimate.

Mr. Falkenberg did not request that PP&L conduct that experiment, although he had ample opportunity to do so. In light of that oversight, I have tested Mr. Falkenberg's hypothesis for him. Additional runs of EGEAS using Mr. Falkenberg's suggested average heat rate approach result in higher and lower market clearing prices during the year. On balance, PP&L's estimated stranded costs fell by 0.8% or $37 million. I conclude that Mr. Falkenberg's contention that PP&L systematically understated market-clearing prices by disregarding the effect of no-load costs and average heat-rates is without merit, apparently designed to alarm the Commission rather than raise a substantive concern.

Q: What about the intervenors' criticism of PP&L's estimate of market-clearing capacity prices?

A: Once again, intervenors fail to account for the dramatic change that competition will bring to the behavior of investors in generation assets. In regulated markets, investors in new generation capacity would be guaranteed an opportunity to receive a return of and on investment, plus a rate sufficiently high to cover variable and fixed costs of operating and maintaining that capacity. Yet, competitive, capital-intensive industries similar to electricity generation, such as metals, cement, oil, and coal thrive without regulatory guarantees. In those industries, investors do not wait for the current price to rise to a level sufficient to guarantee a return of both fixed and variable costs. There are no guarantees and investors know that. Even so, investors sometimes commit capital up to several years in advance of favorable market conditions.

Q: Can you summarize your response to the central issues raised by intervenors regarding the EGEAS modeling methodology?

A: Yes. PPLICA's Mr. Falkenberg argues that my use of a probabilistic model ignores the possibility that a unit may be dispatched at much higher prices for a few hours each year than indicated by the less volatile probabilistic production cost based methodology used in EGEAS. Mr. Falkenberg states that I misapplied the model in determining market prices, seriously understating the revenues derived from the spot energy market. In particular, he argues that it is the effect of random forced outages within PJM that will lead to revenue "windfalls" that would have been captured by another model, but not captured in EGEAS.

This is another case of Mr. Falkenberg alleging a serious error on the part of PP&L's experts without providing the empirical proof that actually demonstrates the validity of the allegation. In this case, Mr. Falkenberg ought to *prove*, and not simply allege, that his modeling approach is more accurate. As I noted in my direct testimony, EGEAS is a commercially available product that has undergone years of peer review and litigation. EGEAS is a soundly tested analytical tool, not a model built specifically for this restructuring filing or even for litigation purposes.

This contention is enforced by further consideration of the competitive forces that would be brought to bear on the marketplace if Mr. Falkenberg's own example of independent outages were carried to its logical conclusion. Mr. Falkenberg argues that EGEAS' probabilistic method would not capture the upside effect on market prices when two nuclear units are down and a third outage occurs.[2] In a competitive market, when two nuclear units are down, competitors will know and react to the possibility of higher market-clearing energy prices. For example, generators with planned outages for that week would simply postpone their units' maintenance schedules, partly in hopes that Mr. Falkenberg's hypothetical third nuclear outage would occur, so competing capacity could enjoy the price increase. However, because all generators would know of the pending opportunity, their competitive response would prevent Mr. Falkenberg's vision of a sustained price spike.[3] In this way, competition tends to lessen

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[2] Direct Testimony and Exhibits of Randall J. Falkenberg, at 45.
[3] Generators are likely to have access to "real-time" system requirements through some form of electronic access such as OASIS.

the duration of peaks and troughs in price cycles. In short, Mr. Falkenberg's suggestion of much higher prices affecting the average annual market-clearing price for energy is not supportable in a competitive market where other generators react quickly to profit opportunities.

The Assumptions Used to Estimate Market Price Should Be Integrated and Logically Consistent with One Another

Q: You have sponsored estimates of future market-clearing energy and capacity prices that rest on estimates of variables like inflation, natural gas prices, etc. Intervenors have also sponsored estimates of others and in some cases offered estimates of their own. Should the Commission pick and choose from the assumptions sponsored by various witnesses in this proceeding when deciding what the market-clearing energy and capacity prices ought to be? Please explain.

A: No. I am sympathetic with the Commission's plight. This is a fact-intensive case with strong sponsorship on all sides of the issues. However, any attempt to force a consensus by changing one variable without considering the relationship of that variable to other variables would undermine the logic linking elements of market behavior and, subsequently, market price.

For example, if the Commission were to rule that it preferred PP&L's assumptions regarding market prices except the forecasted inflation rate, and instead adopted OCA's inflation forecast, pairing the two *would mean* that the Commission would have to explain how the overall rate of inflation could be substantially higher than expected without creating an economic environment that was inconsistent with the market forces affecting electric energy use. Since OCA embraces a forecasted return of significant inflation, use of these data in PP&L's model would mean changing other key variables like (real) fuel prices, the discount rate and, possibly, electricity demand, which may react unfavorably to higher prices.

Q: Can you provide an example of the possible error that simply picking and choosing from various witnesses' testimony might introduce to the forecast for market-clearing prices?

A: Yes. Suppose OCA's version of inflation was limited to its impact just on PP&L's assumed discount rate. The higher inflation rate would imply that PP&L's "investors" would accept a significantly lower real rate of return than PP&L knows to be the case based on its experience in the market. As noted, higher inflation expectations do not stop with discount rates and borrowing costs, but extend much further to expectations about fuel prices, regional and national economic activity, load growth, and other variables.

Q: Can you suggest a way to reduce the apparent complexity of market price determination?

A: The Commission should recognize that it is the assumptions that are important, not the various probabilistic models the utilities and the intervenors have sponsored in this proceeding. No matter which model is used, it is important to "load the model" with a consistent set of assumptions designed to get at the price of energy and capacity. At a minimum, either directly or indirectly, the Commission is going to have to settle on:

1. A single forecast for fuel prices;
3. A single forecast for inflation;
4. A price (in 1996$) for the cost of new capacity (CCs and CTs); and

5. A discount rate to be used in converting future revenues and costs to present values.

Q: Are there variations on what you suggest?

A: Of course, but at the end of the day all participants in this proceeding should agree that the Commission must adopt the testimony of the Company, one of the intervenors, or provide an independent estimate for the inputs necessary to start the process of generating energy prices using a model like EGEAS. PP&L would be willing to run EGEAS using the Commission's selected assumptions.

However, the importance of consistency of assumptions cannot be overstated. The application of proper regulatory policy requires the use of a logically constructed view of the future that can be used to produce market-clearing energy and capacity prices in a competitive environment.

INTERVENORS' ATTACK ON PP&L'S MARKET-CLEARING PRICES INCORRECTLY ASSUMES COMPETITION WILL HAVE LITTLE OR NO IMPACT IN THE MARKETPLACE

Incorporating the Impact of Competition on Electricity Generation Costs and Market Structure Is Essential in Forecasting Market-Clearing Prices for Energy and Capacity

Q: Intervenors' witnesses Mr. Smith, Mr. Falkenberg, and Mr. Knecht criticize a variety of assumptions you used to generate PP&L's market-clearing prices for energy and capacity. How would you characterize their criticisms?

A: The intervenors' witnesses either fail to account for the implications of a move to wholesale and retail competition, ignore the impact of competition on the attempt to forecast market-clearing prices, or distort the facts to fit their point of view that prices for energy and capacity will be much higher than those sponsored by PP&L and more akin to prices formed in a regulated industry.

Q: What are the implications of competition that intervenors' witnesses fail to account for as they criticize your assumptions regarding the market-clearing prices for energy and capacity?

A: The introduction of retail and wholesale competition in much of PJM will create a market environment that can be compared to the shift from regulation to competition seen in other industries. In short, the way business is conducted in today's regulated environment will change forever, increasing choice and lowering costs.

For example, in existing competitive energy or commodity markets (metals, wheat, natural gas, oil, etc.) buyers and sellers enter into a variety of transactions, including term contracts and spot purchases and sales. Buyers and sellers choose between these types of transactions depending on their needs and capabilities, transaction costs, risk management preferences, quality of supply, and other considerations.

Q: How can you be sure that competition will lower both costs and prices?

A: The evidence from other formerly regulated industries is overwhelming. While I can only estimate the effects on electricity markets, the direction is certain. I have attached Exhibit STJ-9 which summarizes the results from the rail, trucking, airline, and natural gas industries and shows that double-digit decreases in prices and costs of production emerged from the move from regulated to competitive markets.

The process of deregulation includes a period of industry restructuring, the "transition period" as envisioned by the Act. Transition periods are characterized by a dynamic realignment of costs, prices, and investor returns that gradually resets stakeholder interests in the industry. For example, before the Staggers Act, railroads were required to incur the costs of maintaining track in regions where the incremental cost of operation exceeded expected revenue. As a result, equity return to shareholders was lessened, hampering railroad access to capital and discouraging profitable investment. With deregulation, assets were rationalized, resetting equity returns with the market and paving the way for today's profitable rail industry with lower shipper costs on most routes.

Q: What costs will decline and how will cost reductions be achieved?

A: Recall that I described the transition period as a dynamic realignment of costs. This means that changes will take place in a series of interactive steps, a change in one variable then impacting another, then another, until the process results in a realignment of stakeholder interests. In that way, all costs will change, mostly declining to levels that were unachievable under the incentives put in place by regulation. Further, the introduction of new technologies and processes will reduce costs through the innovative use of information. Variable O&M cost reduction provides a simple example. Regulated utilities provided most, if not all, of the services needed to maintain generation equipment and attendant facilities. Competitive incentives to reduce all costs will encourage the creation and use of contractor services by which third parties can profit from increased scale of operation and generators can benefit from lower costs with improved service. Specialization among the service providers rapidly displaced certain in-house operations in formerly regulated industries (trucking, airlines, etc.), including O&M costs like vehicle maintenance and certain on-site information systems services.

Q: What are the relevant market conditions facing sellers of electricity, even those seeking to enter into a term contract, once the forces of retail and wholesale competition descend on PJM?

A: Sellers of electricity can and will be able to offer their energy and capacity to the market in PJM. With the advent of wholesale competition and the promise of retail competition, the number of interested sellers (i.e., members of the PJM Interconnection Agreement) has increased well beyond the original number of members. The current membership has already swelled to more than 40 as of early July, 1997, largely in anticipation of the "opening-up" of that relevant geographic market. The interaction of a large and growing number of buyers and sellers is the essence of competition, stimulating interest in offering innovative electric service, increasing levels of service to existing buyers and paving the way for added public benefits such as "green" electricity service alternatives.

Q: How does competition benefit buyers who perceive an on-going need for today's requirements service?

A: Buyers with choice will shop. Buyers who shop may find that a complementary level of electricity service is available at lower prices than those charged by their current provider. Since, other things equal, electricity from one provider is indistinguishable from that of another, the generator with the lowest prices will attract more customers than a higher-priced provider. This choice on the part of customers will create the threat of lost market share, stimulating higher-cost providers or those with non-competitive terms of service to work toward lower costs of generation and, subsequently, lower electricity prices.

Q: How do the intervenors' witnesses ignore the impact of competition in their attempt to set energy and capacity prices?

A: Intervenors' witnesses ignore the effect of competition on market behavior when it suits them. The following is one of the more egregious examples.

> The spread between gas and oil prices and coal prices is crucial in the forecast of stranded cost for PP&L. The reason for this is that in PJM the marginal cost will frequently be determined by gas or oil prices, while most of PP&L's generators are coal-fired. Thus, a wide spread between these prices would tend to forecast a larger profit growth for

PP&L, while a smaller spread would indicate lower profit growth for the company.[4]

Here, PPLICA's Mr. Falkenberg alleges that I deliberately kept the prices for these fossil fuels moving together in my forecast because I want to reduce PP&L's profits, thus enlarging stranded costs. In reality, this statement reflects Mr. Falkenberg's lack of knowledge about competitive fuel markets. I forecast similar trends in oil, gas, and coal prices because fuels compete in the market for industrial and commercial fuel demand. Inter-fuel competition will tend to cause fuel prices to move together over time.[5] Historically, the correlation coefficients are 0.92 between (real) gas and coal prices, 0.9 for oil and coal, indicating that there is no real-world precedent for a sustained and growing "gap" between competing fuels.

Mr. Falkenberg's sponsorship of a forecast that ignores this competitive fact ought to be flatly rejected.

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[4] Direct Testimony and Exhibits of Randall J. Falkenberg, at 34.

[5] Inter-fuel competition encompasses the role of technology and its impact on price/fuel use. Examples are clean-burn coal technologies, direct conversion of natural gas to petroleum products, coal gasification technologies, and so forth.

Q: How grave an error is the sponsorship of a widening gap between oil, gas, and coal?

A: This error is far worse than just getting the forecast wrong. It goes to the heart of one of the central problems with intervenors' testimony: their lack of attention to the consistency of assumptions.

Intervenors assert that I have used "low end" forecasts and conservative estimates for a number of different variables that are part of the market-clearing price forecast. I provide ample evidence in my direct testimony that demonstrates that my assumptions are not independent and therefore are appropriately part of an internally consistent view of the future. Compared to Mr. Falkenberg's methodology, the relationship between my assumptions is much more reflective of the historical trends between different variables which, in turn, provides a reality check on my forecasts. Three examples will illustrate the difference between the consistency of assumptions underlying my forecast and those sponsored by the intervenors' witnesses.

- I have been criticized for using oil prices and inflation forecasts that are at the low end of the universe of forecasts. This does *not* mean that I have embraced an extremely conservative view in the aggregate since energy prices and inflation move together. Since the early 1980s, the correlation between inflation measured as the change in the GDP deflator and real oil prices has been 0.8.

- I am criticized for low-end oil, gas and coal price forecasts. Again, this does not result in extremely conservative aggregate price forecasts since energy prices tend to move with one another (see the data on the previous page), not by chance but because use tends to follow economic trends and the fuels are substitutes for one another in many end-user applications. This co-relationship is the reason my fuel forecasts have the various resource prices moving within the observed historical range for these commodities over the forecast horizon.

- On the other hand, the forecast adopted by PPLICA (EIA) and OCA (DRI) embody fuel price gaps that exceed the historical average oil-coal price gap for most of the forecast period and these estimates *get progressively more unrealistic* as time passes (see Exhibit STJ-10). By the end of the forecast period, intervenors' price gap between oil and coal is well beyond the observed historical range for these fuels. I conducted some tests to see just what the forecasted gap between oil (or gas) and coal prices meant in terms of the likelihood that DRI or EIA's outlook could be right and the results were startling.

- Just ten years into the forecast (2005), and against the historical movement between oil and coal prices, the odds that the gap between oil and coal prices predicted by DRI could materialize are roughly 33,*000:1*.
- The odds that the gap between the fuels forecast for 2005 by the EIA were even worse. There the odds were approximately the same *as a person being struck by lightning more 12,000 times during his or her lifetime*.[6]
- As preposterous as these numbers sound, the intervenors' forecasts get even further outside the realm of historical experience as time passes. The data reveal that there is essentially no chance that fuel prices will behave the way intervenors predict.

The Commission should take at least one thing away from these probabilistic assessments: Even if the intervenors' witnesses

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[6] Bernard Siskin and Jerome Staller, *What are the Chances? Risks, Odds, and Likelihood in Everyday Life*, Crown Publishing: New York, 1989.

got one of the price forecasts (oil or gas versus coal) right, the other would surely be wrong.

Q: Are there other examples where intervenors ignore the effect of a competitive market on the prices of fuel, energy or capacity?

A: Yes. The intervenors' witnesses are also guilty of taking one variable and changing it to support their argument without following the competitive impact of that change to its logical conclusion in the marketplace. For example, Mr. Falkenberg and Mr. Smith argue that my capacity price is too low, particularly before 2002, to bring on anything other than combustion turbine capacity and that a higher capacity price ought to be used instead of the market-clearing price sponsored by PP&L. If intervenors' witnesses followed that allegation to its competitive conclusion they would have to admit that installing the larger combined cycle units early-on would be certain to dampen capacity prices, not raise capacity prices.

In a similar vein, when intervenors' witnesses argue that my fuel price forecasts are too low, replacing my forecast with much higher fuel prices would just cause CC capacity to come on in place of CT capacity sooner in the transition period. The more fuel-efficient CC capacity would cause energy prices to fall as the quantity of electric power increased with the higher capacity factor of the CC unit. This is a good example of the intervenors' witnesses' use of inconsistent assumptions while failing to take the next step to demonstrate the full implication of their allegations.

Intervenors' Witnesses Do Not Fully Develop the Role of Competition in Their Arguments About Changes to Stranded Costs

Q: Do intervenors' witnesses propose arguments that are consistent with a competitive market when they argue about other elements of stranded costs?

A: No. Both Mr. Knecht and Mr. Schoengold propose the sale of generation assets as a means of determining the value of generation assets for purposes of determining stranded costs. Mr. Knecht states, "If a utility can sell its assets at book value, it has no stranded costs. Thus stranded costs could be valued by requiring divestiture of generating plants, by the difference between the market sale price of the asset and book value" (at 33, 16-19). Mr. Schoengold makes a similar suggestion (at 13, 1-4): "Since the purpose of estimating the market price is to determine the value of the existing plants, use of an auction to determine the actual market value of the power plants renders the administratively determined market price superfluous."

Q: What problems does an asset auction pose for utilities and ratepayers?

A: There are a number of problems with the required sale of the plants, either bilaterally or at auction.

- The Act does not envision the sale of generation assets to determine the amount of stranded costs.[7]
- The Act envisions an orderly transition, not an instantaneous adjustment in 1999 from the past to the future.[8]
- Requiring owners to auction generation assets is not likely to provide a reasonable indication of the assets' value for reasons that are heavily influenced by competitive market conditions.

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[7] Section 2803 of the Act defines stranded costs as the "measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market ..." Further, in Section 2804(5), the Act states that "The Commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure."

[8] The recommendations posed by Enron's Dr. Mayo in section IV of his direct testimony beginning at p. 24 violate this underlying purpose of the Act which sponsors an orderly transition. Professor Mayo's application of economic principles to restructuring envisions the full impact of competitive market conditions beginning in 1999 without the benefits of the transition period through 2005.

- ⇒ If all Pennsylvania utilities were forced to complete a sale on short notice, the number of interested bidders would be drastically diminished and the naturally conservative bids would not reflect the full economic content of the generation assets.

- Mr. Schoengold's suggested postponement of the auctions is also riddled with problems.
  - ⇒ The whole point of the auction is to provide an alternative method by which to ascertain the market value of generation assets.
  - ⇒ An auction that is several years away cannot provide this information within the required time frame.
- In competitive commodity markets, competitors will tend to use financial management tools to reduce the risk associated with their natural "long" position (i.e., as generators of electricity or as growers of wheat). This business tool would be unavailable to companies that are told to dispose of their assets, foreclosing utility management from the ability to utilize these tools and raising generation costs.

- Competitive generation markets could turn a forced asset sale policy into labor force chaos as workers react to the expectation of changes. Reduced labor-force productivity will prevent post-deregulation labor cost savings from being realized as morale and worker productivity decline.[9]

Q: Are intervenors' own estimates of market-clearing energy prices consistent with plans on file with PJM?

A: No. Intervenors' witnesses criticize my market-clearing price forecast and argue that much higher prices ought to be used in place of my estimates. However, my estimates are derived from the current demand forecast that underlies PJM's system operations. The implication that prices ought to be significantly higher is not consistent with the changes forecast in electricity demand for PJM without considerable explanation and additional

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[9] Research shows that asset disposition is usually followed by the winning bidder going on a cost-cutting effort, and employees will act as if the winning bidder will reduce headcount. Layoff pronouncement has a strongly negative impact on worker morale and productivity, disadvantaging incumbent generators in a competitive environment. See Mark Richey, "The Impact of Corporate Downsizing on Employees," Business Forum, 1992; Joseph McCune, Richard Beatty, and Raymond Montagno, "Downsizing Practices in Manufacturing Firms," Human Resource Management, 1988; Philip Greco and Brenda Woodlock, "Downsizing the Organization," Personnel Administrator, 1989; Kim Cameron, "Strategies for Successful Organizational Downsizing," Human Resource Management, 1994.

evidence as to what set of variables would actually produce the higher energy and capacity prices. Intervenors' must have in mind another level of market activity. Unfortunately, intervenors' do not supply a revised demand forecast and the other changes needed to support that forecast. This appears to be another instance where intervenors' simply allege that their view ought to prevail without describing a consistent set of assumptions to support their belief that prices ought to be higher than those sponsored by PP&L.

Given an Opportunity to Show the Impact of Competition on Stranded Costs Using a Consistent Set of Assumptions, Intervenors Stop Short of Completing that Task

Q: Can you describe a situation where it appeared the intervenors were going to use a consistent set of assumptions when estimating changes in stranded costs?

A: Yes. OCA requested that PP&L re-run EGEAS using their assumptions for inflation, fuel prices and capacity prices. I responded to Set VIII, Interrogatory Request of the Office of Consumer Advocate, May 13, 1997 in a supplemental response dated 6/27/97 showing the impact of their assumptions on market-clearing prices for energy displayed as the annual average price and comparable to my Exhibit STJ-7. I have attached that interrogatory response as Exhibit STJ-11 for reference.

The market-clearing energy prices were generally lower in the early years and higher in the later years than the data in my Exhibit STJ-7. However, a far more interesting story is revealed by running the OCA results through Mr. Schadt's stranded cost model and examining the results. OCA requested that a much higher market-clearing capacity price be substituted for the prices I show in Exhibit STJ-8. OCA suggested $30/KW for 1998, $43/KW for 1999 with all other years following a higher, ever-increasing inflation forecast beginning with 2.7% in 2000 to 3.7% in 2015. This combined with OCA's lower nuclear capacity factor of 75% meant it was cheaper to bring on new combined cycle (CC) units and the units would be needed sooner in PJM because less costly nuclear capacity was not there to displace system growth.

OCA's request to use its assumptions in EGEAS clearly demonstrated what happens when high fuel prices and high inflation forecasts are paired with PJM's existing demand forecast. The much higher prices and lower nuclear capacity factor cause more CC capacity to be brought sooner than the expansion plan I used to generate PP&L's view of market-clearing prices. The new CC capacity is much more efficient than PJM's existing (higher-cost) coal-fired capacity, supplying PJM's need for capacity much of the year at or below market-clearing prices. As a result, existing PP&L fossil capacity is dispatched less than it is today, stranding those assets for more of the year above market-clearing prices set by OCA's fuel and inflation forecasts. The change in PP&L's stranded cost claim is significant using OCA's assumptions. PP&L's stranded costs *rise* by $165 million dollars compared to the Company's estimate that appears in Mr. Schadt's Direct Testimony.[10]

This result graphically demonstrates how intervenors' arguments about higher fuel prices, capacity prices and inflation, when taken to their logical competitive conclusion, actually work to *increase stranded costs,* not consistently decrease stranded costs as intervenors would have the Commission believe.

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[10] All of the increase in stranded cost occurs in the fossil fuel units because the coal-fired generation capacity that would have been dispatched using PP&L's assumed capacity prices, fuel prices and inflation are idled by OCA's assumptions that bring on more new CC units sooner during the transition period.

PP&L's Fuel Forecasts Are Reasonable

Q: How do you respond to intervenors' complaints that PP&L's fuel price forecasts are too low?

A: Based on my 20 years of experience in the energy industry, as an energy industry corporate executive, as a consultant to the energy industry, as senior manager of the second largest forecasting firm in the world, and as a trained economist, it is my opinion that PP&L's fuel price forecasts are reasonable. Intervenors' forecasts suffer from a number of problems. Some are obvious, like the "starting point" error that was also pointed out by PECO.[11] Others require my years of experience to put in perspective. These include the all-too-familiar "dog-leg" in the price path, the recurrence of an improbable rate of inflation, and the folly of assuming a growing gap between oil/gas and coal prices.

The Problems with Intervenors' Forecasts Are Serious

Q: Can you briefly explain each of the problems with intervenors' fuel price forecasts?

[11] Rebuttal Testimony of William A. Hieronymous on behalf of PECO, at 20.

A: The starting-point problem is due to intervenors' witnesses use of an out-of-date forecasted rate of change for fuel prices that was subsequently applied to actual 1996 energy prices. This starting-point problem shifts all forecasted prices up by the magnitude of the error as noted in Exhibit STJ-12.

I used 1996 actual prices as the basis for my forecast of fuel price changes. As a result, my forecast is much more like the update issued this Spring from EIA.

Mr. Smith used an out-of-date 1996 DRI forecast that also results in a reversal of the trend in predicted oil prices.[12] In its Spring, 1997, forecast DRI replaced its 1996 forecast with a dramatically different nominal oil price decline as follows: 1996=$20.71, 1997=$19.41, 1998=$18.90, 1999=$18.47, and $18.98 for 2000. Despite the wholesale change in direction of their forecast, from rising prices predicted in the Winter of 1996 to falling prices predicted in the May, 1997 *Outlook*, the new data make sense against an end-of-year 1996 actual oil price. I would also note that DRI's revised forecast is now very similar to my forecast,

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[12] It is particularly troubling that Mr. Smith persisted to use the out-of-date numbers even though DRI updated its forecast down sharply as early as March 10, 1997 (see *Monthly U.S. Forecast Bulletin*), many weeks before Mr. Smith filed his testimony.

the basis of the market-clearing prices submitted by PP&L in this proceeding. As shown in Exhibit STJ-13, my forecast is somewhat less aggressive than that proposed by DRI up to 2004. DRI's updated fuel price forecast would result in higher stranded costs than my fuel price forecast.

Q: What did you mean by a "dog-legged" forecast?

A: The forecast "dog-leg" is a very serious problem. The dog-leg is the historic tendency for DRI and EIA to include a severe upward bend in the later years of their forecasts of energy prices (see Exhibits STJ-14-a for oil and STJ-14-b for natural gas prices). The propensity for energy price escalation to gradually rise, then accelerate for several years, is without historical precedent and results in a widened forecast error.[13] Both the dog-leg and the persistent bias toward higher than actual energy prices are problems that many within the energy industry have recognized. Indeed, the oil industry provides one view of the future in New York Mercantile Exchange pricing. Oil futures closed December, 1996,

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[13] The forecast error between EIA predictions and actual oil and gas price movements from the early 1980s to 1995 is well over 100%. As prices stabilized, the forecast error declined, but remained positive at about 40%. Source: EIA, *Issues in Midterm Analysis and Forecasting*, 1997.

at about $25/Bbl. In February of this year, futures prices averaged $20.25 for December, 1997, $19.70 for December, 1998, and $19.70 for 1999. Hence, the industry was signaling declining real prices consistent with my forecast. In summary, I find intervenors' reliance on DRI's and EIA's ever-increasing oil price forecasts to be even more surprising in light of Mr. Falkenberg's testimony: "For years many of the most reputable sources have projected increases in fuel prices in general, and escalation above the rate of inflation for gas and oil. Instead, fuel prices have either dropped, stayed flat, or oscillated with no discernible trend."[14] Mr. Falkenberg's own testimony would suggest that the Commission should look somewhere other than DRI or even EIA for a reliable long-term fuel forecast.

The Commission Can Resolve Many of the Differences Between Forecasts

Q: Is there a remedy to the problem of overestimating future energy price changes?

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[14] Direct Testimony of Randall J. Falkenberg, Application of PECO Energy Company for Approval of Its Restructuring Plan, Docket No. R-00973953, at 17, lines 16-18.

A: Forecasts are almost all going to be wrong; it is just a matter of time. Hence, I looked toward historical energy price trends in order to minimize the possibility of that error in my fuel price forecast. Since I cannot find a body of evidence that would lead me to attempt to "fine-tune" a forecast of oil or gas prices other than allowing the 1996 price spike to work itself out of the market by 1999, I simply hold (real) post-1999 fuel prices flat. That way I implicitly recognize two major characteristics of the fuels market:

1. Historic (long-term) oil prices follow a flat real price trend, and
2. Fuel-to-fuel competition has and will continue to dampen sustained fuel price changes and cause prices to follow one another over the long term.

There is no reason not to adopt this method for inflation as well.

- The decade-long period of stable or declining inflation continues unabated. Hence, I selected a single, reasonable rate of inflation and used that inflation rate throughout the forecasted horizon.

- Forecasters have consistently over-estimated inflation since 1987.[15]

If the Commission were to adopt the use of a consistent rate of fuel price change and inflation, some of the difference between the utilities' and the intervenors' forecasts disappears. I have prepared tables for Exhibit STJ-15-a and STJ-15-b that show the impact on energy prices and capacity prices of using a constant 2.5% inflation rate. For purposes of comparison, the data in those tables are also shown with the data from the Rebuttal Testimony of Mr. John Bustard on behalf of PECO where he collected the data without adjusting for the different rates of inflation. The exhibits show that with the exception of OCA's Mr. Smith's forecast for energy price in the "out-years" (the DRI dog-leg has kicked in) and PPLICA's Mr. Falkenberg's forecast for energy that suffers from the starting-point problem, all the forecasts are much closer using a constant rate of inflation. This suggests that the Commission ought to take a hard, independent look at the estimates of inflation separate from the estimates for real fuel prices (keeping in mind

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[15] Direct Testimony of Frank C. Graves on behalf of Met-Ed/Penelec, Docket No. R-00974009, Exhibit FCG-1.

the internal consistency required by the high observed correlations between them).

PP&L's Forecasts Are Not Derived from a Consensus of Low Energy Price Forecast Scenarios

Q: Various intervenors' witnesses (e.g., Mr. Falkenberg at 31 and Mr. Smith at 10) argue that you use a consensus of "low" forecasts that were available at the time you prepared your testimony. How do you respond to that allegation?

A: In my direct testimony, I said that I preferred to examine the assumptions and predicted prices from more than one organization when assessing the path energy prices might take in the future. In that way, I benefited from the judgment arrived at by a variety of individuals and organizations concerned with forecasting oil, gas, coal and uranium prices. Each published forecast, and the underlying assumptions, offers one structured (sometimes) consistent view of how prices might behave.

Q: Did you just focus on the assumptions and views of the "low" forecast scenarios published by the firms cited on page 31 of Mr. Falkenberg's testimony?

A: No. In fact, I considered forecast assumptions that drove "high", "base case" and "low" fuel price scenarios, but in order to present the Commission with a reliable, long-term market price forecast, I was guided mainly by actual changes in oil and gas prices during this century.

The Facts Support Using History as a Guide to Future Fuel Price Trends in a Competitive Market

Q: Why were you influenced by the actual trend in oil and gas prices?

A: There are a number of important reasons.

- As illustrated in Exhibit STJ-16, once oil prices are adjusted for inflation and for the unprecedented price spike caused by the Iranian Revolution (but *including* price increases caused by the recent Gulf War and the original Arab Embargo), oil prices have fluctuated in a reasonably narrow range about a flat real price trend of $15.50/Bbl (1996$).
- Oil, gas, and coal prices are formed in highly competitive fuels markets where inter-fuel competition plays a major role in the way prices move over time.
- As a result, consumers can expect to face prices that tend to move together and fluctuate in response to market conditions.

The historical correspondence between utility fuels is clearly shown in Exhibit STJ-16-a, along with some statistical tests for PP&L's forecast values and those of the intervenors' witnesses. The first matrix in that exhibit shows correlation coefficients based on historical (real) price movements for oil, coal, natural gas and uranium. Correlation coefficients in excess of 0.8 indicate a very strong tendency for the variables (i.e., oil with coal, coal with gas, etc.) to move together over time. The second matrix shows the correlation coefficients for the PP&L forecast values. As I have noted elsewhere, the forecast changes were deliberately tied to one another in the expectation that forecasts ought to closely approximate historical trends.

The third and fourth matrices shown in the exhibit contain the correlation coefficients for the OCA and PPLICA forecasted fuel prices. All the coefficients ought to be *positive and very high*, like the data in the first matrix. Sadly, they are not, revealing the absence of consistency in the intervenors' forecasts in the context of the way fuel prices have historically changed. The DRI forecast, the basis for OCA's fuel price estimates, not only fails to closely match historical trends, but *trends strongly in the opposite direction.* A correlation coefficient of about minus one (-1.0) means that the two series move away from one another like the positive and negative poles of two magnets. There is clearly no support for this forecast.

The EIA forecast also fails to correspond to historical trends. The correlation coefficients are positive, but relatively small (i.e., closer to zero) than those from the PP&L forecast. For example, the EIA forecasts the correlation in price movements between oil or gas and uranium at 0.18 and 0.38, where history suggests the movements ought to correlate at 0.88 and 0.85, respectively. Hence, rather than a forecast where the prices move together, the EIA forecast allows fuels to part company with one another.

- By examining oil price behavior since 1900, I can observe the duration of periods where these forces have produced sustained periods of successively higher and lower energy prices.

- By examining where prices have been through 1996, I can get some idea of where full-year 1996 prices sit in comparison to a probable range for long-term utility-fuel prices.
- The forecasts selected by intervenors can then be compared with actual price movements over time and examined for the extent of forecast error.

All of these considerations, not just a few "low" forecasts cited by intervenors, are the basis for PP&L's fuel price forecasts.

Oil Prices for the Last 100 Years Track a Flat Real Trend

Q: Can you explain each of your reasons for relying on the actual price movements when producing the escalation rates for PP&L's fuel prices?

A: Yes. As shown in Exhibit STJ-16, after adjusting for inflation, the 96-year path in oil prices is remarkably stable. The average price of oil since 1990 is $15.50/Bbl (1996$).

Q: What do you mean by remarkably stable?

A: I suspect that most people believe there has been more volatility in oil prices than actually occurred. However, the data shown in Exhibit STJ-16 indicate that last year's average wellhead price has been exceeded only 9 *times*, or 18% of the time, during the last 50 years. Importantly, when prices were higher than last year, the average difference was only about $2/Bbl (about 11%). So, DRI's price forecasts, which consistently exceed this range have very little chance of occurring at all and ought to be excluded.

Q: What other facts can be taken from the data shown in Exhibit STJ-16?

A: There are several more interesting characteristics of competitive fuel markets that can be discussed in light of the data in the exhibit.

- While real oil prices have been relatively stable, global oil production has grown more than three-fold just since 1960. I suspect that this, also, runs counter to what most people might believe, since oil has long been cast as a "finite resource," subject to depletion and shortages. However, that simply has not been the case.[16]

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[16] In the past, forecasters have used the concept of a finite resource to link a forecasted increase in oil demand to the necessity to incur increased real production costs and prices for energy resources like oil, gas, coal, and uranium. But as the data for oil show, that is wholly unsupported by history. M. A. Adelman, the noted resource economist comments on the notion of finite resources in *The Economics of Petroleum Supply*, MIT Press, 1993. He writes, "Perhaps the very concept of exhaustible resources ought to be discarded as wrong or irrelevant. Not much of the resources known today will be used because better ones will be found."

- The ability of the industry to replace what consumers use is particularly true for natural gas. Exhibit STJ-17 shows that all of the proved gas reserves known in 1987 have been consumed by 1997. If hydrocarbon resources were strictly finite, in an economic sense, then today's price would not be lower and reserves higher than a decade ago.
- The average wellhead price for 1996 appears near the probable ceiling for oil prices as shown in Exhibit STJ-16.[17]
- Historical price movements indicate that a real price decline has been sustained from 5 to 15 years, whereas price increases have never lasted more than about four years without a significant price correction.[18] Given these facts, I would expect the average wellhead prices in 1997 to be lower, in real terms, than the price recorded in 1996.[19]

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[17] That range represents one standard deviation about the century-long trend in real prices. The range is $3.40/Bbl, about a $15.50 average barrel, indicating that there are 7 chances in 10 that the future price of oil each year will be between $12/Bbl and $19/Bbl, with the probable outcome near $15.50/Bbl (1996$).

[18] The most notable period of sustained price change began in the late 1950s when retail prices declined until 1972. This period corresponds to the "opening-up" of the vast oil resources in the Middle East to production by the world's largest oil companies. Shorter price declines were sustained during the first decade of this century (1906-11), from the mid-1920s to the early 1930s, from 1982 through 1986, and most recently from early-1991 to 1994. Shorter, sustained real price increases were recorded in the early 1920s, the mid-1930s and most recently during the original Arab Oil Embargo of the 1970s.

[19] So far, prices in 1997 have declined markedly from late 1996 levels and appear to be headed lower still.

- Researchers have discovered that oil prices, over long periods of time, tend to be "mean reverting".[20] If this is the case, then over long periods of time, fuel prices may rise temporarily but will trend back downward. If supply side increases in technology outstrip demand, the mean itself, i.e., the price level to which prices converge over time, will decrease in real terms. Simple observation of the path of oil prices in this century suggests that an element of mean reversion is present (see Exhibit STJ-16).

PP&L's Oil Price Outlook Differs Substantially from Intervenors' Forecasts for Several Reasons

Q: How does your oil price forecast compare to that of PPLICA's Mr. Falkenberg when "fit" into the context of historical oil price changes?

A: Mr. Falkenberg's oil and gas forecast demonstrates a sustained 20-year increase in real prices. This is wholly unsupported by historical precedent. There have been no sustained real price increases during this century. My forecast shows a real price

[20] R. S. Pindyck and D.L. Rubinfeld, *Economic Models & Economic Forecasts*, 3rd edition, McGraw-Hill, 1991, 462-463, and A.K. Dixit and R.S. Pindyck, *Investment Under Uncertainty*, Princeton University Press, 1994, 403-405.

decline from 1996 through 1999, representing the expected downward trend of oil prices toward the long-run average price.[21] After that, I have held real prices constant. The two forecasts are shown in the "blow-up" as part of Exhibit STJ-18.

Q: Please review why you held real prices constant after 1999?

A: There are two main reasons.

- Real prices tend to be stable over long periods of time. Consider the changes in oil prices over just the last ten years. Over that period, the average (real) oil price was $17.90/Bbl, a price within cents of my projected (real) oil price for 1999 and beyond.
- Forecasting organizations tend to do a very poor job of predicting intermediate and long-term oil prices.

The organizations generally predict a price that turns out to be too high almost immediately, then "dog-legged" upward for years in the future. My experience in the energy industry suggests that if I had relied on organizations like DRI or the EIA for a long term view of

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[21] In actuality, the long run average price is probably declining due to supply-side technology advances; however, I have been conservative and have not explicitly accounted for their effect.

energy prices, I would have knowingly built in a bias to the forecast. In fact, unlike the NYMEX futures prices referred to above, the industry does not buy or sell oil using contracts based on DRI/EIA forecasts. It is the absence of a market-based reality check that allows these agencies to repeatedly overestimate future prices. Hence, since I have no reliable information to the contrary, I simply relied heavily on historic precedent and fuel-to-fuel competition in holding real oil and gas prices flat for *the final* 15 years of the forecast horizon.

Q: What are the implications of Mr. Falkenberg's forecast relative to the recent history of oil price behavior?

A: Examples will help illustrate the magnitude of the potential forecast error embedded in Mr. Falkenberg's fuel price outlook.

- The forecast Mr. Falkenberg uses substantially increases the real price of oil between 2000 and 2015. In a competitive market, this would bring on substitute fuels and fuel-related technology (e.g., natural gas conversion) that would dampen this increase long before 2015.

- The average (real) wellhead price of oil averaged about $18/Bbl over the last ten years, within a few cents of today's price. Yet, the last ten years have seen a 12% increase in oil demand and the price spike caused by the 1990 Gulf War. Clearly, the supply-side of the market matters a great deal, and responds quickly to changes in market price, and yet, the supply response appears to be ignored when considered against the rise in intervenors' real price escalators.

Q: Based on your more than twenty years experience with the formation of energy prices, what is the fundamental problem with intervenors' use of the DRI and EIA fuel forecasts?

A: There are several chapters to this story, some of which are drawn from my many years of experience with the forecasting community.

- The DRI and EIA models are derived from the same family of econometric tools first built in the 1960s and 1970s.
- The genesis of these models was the work of a handful of economists who turned their academic research into companies

to service the growing demand for forecasts of economic activity.[22]

- Despite refinements to the energy models, those forecasting tools are still rooted in the trends economists feed into the macro-model each time a forecast is generated.

Exhibit STJ-19 shows that the EIA and DRI forecasts track one another so closely that even during periods of oil price volatility, the difference between the two is very small.

Q: In your opinion, what are the reasons for DRI and the EIA to consistently over-estimate future oil and gas price movements in the long run?

A: There are at least two reasons.

- The models have their roots firmly entrenched in the macroeconomy, and long-term economic forecasts usually do not include recessions. Hence, economic activity is consistently

[22] The heyday of these models brought tremendous public attention to the founders and their companies, as corporate and government leaders sought answers for the economic turmoil of the early 1970s. Throughout the 1970s and much of the 1980s this industry was dominated by the three original forecasting firms: DRI (founded by Otto Eckstein), Chase Econometrics (founded by Mike Evans and Chase Manhattan Bank) and Wharton Econometrics (founded by Nobel winner Larry Klein). In addition, government agencies like the EIA began to construct models of their own patterned after DRI and Wharton.

forecast to improve and that upward bias is transmitted to the energy models.

- In reality, the energy industry irregularly adds supply in "lumps." It also reduces costs through technical innovation that lowers costs. Neither cost reduction or supply additions are consistent with the regular, smooth, quarter-to-quarter changes that drive economic models.

Q: Can you cite an example from one of DRI's long-term forecasts?

A: In the DRI Fall/Winter 1993/94 *International Oil Bulletin*, at 7, their energy analysts state that the demand on Middle East OPEC oil will increase forcing those countries to spend more than $100 billion to expand oil production capability: "Thus, in order to make the necessary investments in new capacity and fuel their oil-dependent economies, OPEC producers will need higher prices."

Their conclusion is embarrassingly naive. At current prices, capital spent on added production from Middle East oil fields would be recovered very quickly (in months, not years) without impacting their oil-dependent economies.

Q: Do forecasts of natural gas prices suffer from the same problems you have identified with respect to oil prices?

A: Yes. In Exhibit STJ-17 I introduce the idea that gas supply is much more fungible than most people believe. Hence, added gas reserves can be coaxed into the market without a large increase in expected natural gas prices. In addition, there is evidence that forecasters tend to overstate gas demand for electric generation. I have summarized a number of those reasons in Exhibit STJ-20. Hence, because of competition, there is little evidence that a real long-term price increase could be sustained as forecast by Mr. Falkenberg or Mr. Smith.

PP&L's Use of a 2.5% Rate of Inflation Is Appropriate

Q: Why do you disagree with the intervenors' criticisms that your use of a constant 2.5 percent inflation rate is too low, particularly when compared to the forecasts used by DRI and the EIA?

A: There are several reasons.

- Relying on forecasting organizations' outlook for inflation forecast in the past would have produced the same upwardly biased forecast error that oil and gas forecasts exhibit. Exhibit STJ-21 shows the propensity of both DRI's and EIA's inflation outlook to move together over long periods of time and predict an increasing rate of inflation as the forecast horizon lengthens.[23]
- The appropriate rate of inflation to use in assessing the inflation facing PP&L cannot stem from consumer products. Any use of the Consumer Price Index (CPI) would be ludicrous on its face, even if the Senate Finance Committee's report had not concluded that the CPI overstates inflation by as much as 1%/year.[24]
- The GDP deflator is at best a compromise as a measure of price change. The down-side is that the GDP deflator includes long-lived assets as if they were purchased monthly.

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[23] As Mr. Frank Graves, on behalf of Met-Ed/Penelec, Docket No. R-009774009, notes "actual GDPD has been below forecasted levels for essentially all of the forecasts made in the last decade by the Blue Chip consensus. This may be because macroeconomic models tend to forecast more resource scarcity in the distant future than often occurs (especially for important commodities like oil, natural gas and metals) and tend not to forecast improvements in technology." (Testimony at 8)

[24] Boskin, M.J., et al., *Toward a More Accurate Measure of the Cost of Living*, Final Report to the Senate Finance Committee, December 1996.

- A more representative measure for the rate of change in inflation facing an industrial firm like PP&L might be the Producer Price Index (PPI), a measure of the rate of change in the prices received by industry for the goods it produces. I would note that forecasts of the PPI, even by DRI, average less than 2.5 percent per year. Since I can find no evidence, either in a long-term view of the macroeconomy or in the regulatory policy of the Federal Reserve Board that suggests a propensity toward monetary expansion, I have fixed the inflation rate at 2.5%.

Intervenors' Criticisms of a Number of Technical Issues Are Simply Wrong

Intervenors' Claim that I Have Systematically Understated Heat Rates and Market-Clearing Prices Is Without Merit

Q: Will you please comment on OCA's Mr. Smith and Mr. Falkenberg's criticism of how you modeled the heat rate curves of generation units.

A: Mr. Smith and Mr. Falkenberg argue that by modeling the heat rate curves of generation units in incremental blocks, EGEAS "systematically understates the market-clearing price."[25] Their reasoning is that the incremental cost of some blocks of a unit is below the variable cost for that unit operating at certain loads. Therefore, if the unit is operated at such a load level, the unit would not recover its variable costs and would lose money on every sale. In a competitive market, generation owners would ensure that their bids recover their total variable costs.

Q: What is wrong with their argument?

A: As a matter of theory, their argument has a ring of truth, but the conclusion they draw from their argument cannot be supported by empirical evidence. In a competitive market, generation owners will bid the maximum of their incremental costs and their average variable costs (Mr. Falkenberg's "all variable costs"[26]) for each block of their generation unit. Exhibit STJ-22 illustrates this point. Loading blocks in which the incremental cost is below variable costs at that level of operation are designated as Area A on Exhibit

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[25] Smith, page 5, lines 14-15. Mr. Falkenberg uses similar language on page 24, lines 8-11. He states: "As a result, Dr. Jones has systematically assumed that generators will bid at prices below their actual variable production cost and operate many hours during the year at prices below their average cost of fuel. The net result is to substantially drive down the market price of energy."

[26] Direct Testimony and Exhibits of Randall J. Falkenberg, at 18, line 2.

STJ-22. A unit that receives its incremental cost for those blocks would not recover its variable costs.[27] On the other hand, for loading levels in which incremental cost exceeds variable cost, a generation owner would bid its incremental costs in order to maximize its energy margin. Intervenors Mr. Smith and Mr. Falkenberg wrongly describe how competitive generators would bid by confusing the use of variable costs with the proper incentives as signaled by incremental costs. Intervenors' witnesses would understate the market-clearing price in those instances when the unit's variable cost is below the unit's incremental cost.

Q: Please describe how Mr. Smith and Mr. Falkenberg propose to model heat rates.

A: Intervenors' witnesses propose to model the heat rate curve of each generation unit as the "as-operated" heat rate and the "full load heat rate."[28] In Exhibit STJ-23, I have taken the average variable heat rate curve and the incremental heat rate curve and combined them into a "Generator's Bid" heat rate curve, which is

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[27] I described this situation in Response to OCA Data Request Set III, Q45 (part b).

[28] Direct Testimony and Exhibits of Douglas C. Smith, page 8, lines 8-10, and Randall J. Falkenberg, page 25, lines 7-8, respectively.

the maximum of the two previously mentioned curves. In addition, I have plotted the heat rate "curve" (i.e., a straight line) that intervenors Mr. Smith and Mr. Falkenberg propose.

Three items are worth mentioning.

- The proposed Smith-Falkenberg curve is sometimes higher than and sometimes lower than the Generator's Bid heat rate curve, meaning that under their proposal sometimes they would underestimate the market-clearing price for energy and sometimes they would overestimate it.
- Intervenors model the heat rate curve of a unit as a single number. This modeling approach is inconsistent with their observation that incremental heat rate curves are not the same as average heat rate curves.
- The reason that the curves are not the same is that the efficiency characteristics of many generation units vary substantially over their operating range. Intervenors' criticism of EGEAS heat-rate modeling is therefore inconsistent with their simplistic modeling of heat rate curves.

Q: Dr. Jones, describe how you tested the effect of modeling the heat rate characteristics of generation units as proposed by the intervenors.

A: Since the intervenors' proposed method of modeling the heat rate curve sometimes overstates and sometimes understates the market-clearing price for energy, I re-ran the EGEAS model, replacing the incremental heat rates with the average heat rate to see what effect (if any) this had on annual average prices as shown in Exhibit STJ-7. The results, which are presented in Exhibit STJ-24, vary across years, but energy prices are, on average, *slightly lower* by $0.09/MWh using intervenors' average heat rate. On that basis, I conclude that Mr. Falkenberg's allegation that I systematically underestimated the market-clearing price for energy is totally without merit.

Q: In summary, can you offer any insight as to why your empirical findings contradict Mr. Falkenberg's assertions and support PP&L's estimate of market-clearing price?

A: There are two basic reasons why Mr. Falkenberg's allegation cannot be supported.

- First, I suspect that part of the problem lies in his misunderstanding of the economic principles that drive competitive markets. His attempt to use an "airline example" illustrates this lack of understanding.

> Assume you own a commercial airline and are considering starting service from Harrisburg to Washington, D.C. The cost of flying an empty jet on this route is substantial. This cost is clearly variable cost and it would be incurred *before* any passengers are carried. The *incremental* cost of flying an additional 180 pound passenger is virtually unnoticeable compared to the cost of flying a 100-ton jet plane. Would you last long in the airline business if market prices were sufficient only to cover the incremental cost of carrying one additional passenger, while ignoring the cost of flying the empty plane and crew on your route? I doubt it. Instead, the reasonable business person would only fly such a route if the prices charged were sufficient to cover the average variable cost of the entire trip (the variable cost of flying the empty plane, crew, *and* the extra passenger).[29]

Mr. Falkenberg's hypothetical example actually shows precisely why, in the short term, airlines do fly with fewer passengers than it takes to cover all fixed and variable costs. Once the airline commits to fly this Harrisburg to Washington route, the cost of the plane, its crew, etc. are fixed costs, while the only variable costs are things like the soda and peanuts

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[29] Direct testimony of Randall J. Falkenberg at 18-19.

served to its passenger. Hence, as long as the fare received from this passenger exceeds those small variable costs, that revenue will be contributing to the fixed costs of having committed to fly the route. The passenger's money will be accepted in a competitive world, at least in the short run. In Mr. Falkenberg's world, airplanes would only leave the gate when enough passengers were on board to cover the average variable cost of the trip.

- Second, the EGEAS model used by PP&L was designed for long-term planning and forecasting like the analysis required by the Act. EGEAS dispatches blocks of units, just like PJM actually dispatches the system. When deciding to dispatch a particular block in that unit, EGEAS checks to see if dispatching the next block lowers the average cost of operating that particular unit. If it does, EGEAS will proceed to dispatch that next block, along with any other sequential blocks that lower the average cost of operating that particular generation unit. As a result, units are usually dispatched in a manner fully consistent with a competitive market, at an operating point in which the average variable cost is approximately the incremental cost.

PP&L's Capacity Price Forecast Is Reasonable

Q: Dr. Jones, what are the issues raised by the intervenors regarding your capacity price data and modeling?

A: Several intervenors' witnesses (Falkenberg, Smith, and Knecht) argue that my capital costs for combined cycle units (CCs) and combustion turbine units (CTs) are too low, that the heat rates associated with these new units are too low, that I did not include many additional costs that would be incurred in constructing a new facility, that my estimates of operation and maintenance expenditures (O&M) are too low, that I have overstated the performance (e.g., durability) of these new units, and that my capacity price forecast is not sufficiently high to cover all the costs associated with building new units.

Q: Dr. Jones, please summarize the major cost and performance assumptions used by the intervenors and yourself.

A: In the following table, I compare the capital costs of a CC and its heat rate assumptions used by the intervenors and by me.

Assumption	Mr. Smith	Mr. Falkenberg	Dr. Jones
Capital Cost	$550	$595	$595

($/kW)			
Heat Rate (BTU/kWh)	6,700	7,000	7,000

As the table clearly demonstrates, the assumptions used by the intervenors are as optimistic as or more optimistic than the ones I used. Hence, intervenors criticisms regarding the cost and heat rate assumptions in my analysis are fallacious and without merit.

Q: Dr. Jones, please provide a range of vendor prices for a CC built today.

A: Exhibit STJ-25 graphs various heat rate characteristics of a CC built today versus vendor prices ($/kW). In this exhibit there are two groups of data points and one additional data point. The first "unadjusted group" of data points represent vendor prices and heat rates as reported in *Gas Turbine World 1996*, the source referenced in Mr. Falkenberg's testimony. To the right of this group of data points are those used in Mr. Falkenberg's testimony.[30] Mr. Falkenberg selectively adjusts these data to reflect summer turbine efficiencies which bias CC costs upward, in line with his thesis,

[30] Exhibit No.___(RJF-6).

despite the fact that these adjustments do not apply most of the year. Finally, on this graph I have plotted the data point associated with my capital cost and heat rate assumptions. Notice that this point is above and to the right of even the "adjusted group."

Q: Does that mean that you agree with Mr. Falkenberg's adjustment shifting the plot of new technologies up and to the right or that your assumptions regarding CC costs/heat rates should be characterized as optimistic?

A: No. My assumptions simply reflect what I know to be the average cost/heat rate for the best technology today, based on units in place and operating for the last few years. By 2000-2001, the point when investors will decide what to install in 2002, some of the units in Exhibit STJ-25 will have proven to be the best combination of costs and heat rates. These are all clearly lower than the example I chose from units up and running as of 1996.

A simple comparison of "yesterday's" best CC technology with that shown by Mr. Falkenberg will serve to make my point. I compared the heat rates cited by manufacturers from the *Gas Turbine World Handbook*,1992-1993 with those cited in the 1996 edition. The latest of the *Handbook* cites heat rates for large (>200 MW) new models at about 6,000 BTU/kWh. Heat rates for similarly sized new models for these manufacturers (ABB, GE, etc.) in 1992-1993 ranged from about 300 to 800 BTU/kWh higher. Since my forecast expects the first new CC to be installed in 2002, several years of technical advancement will occur meaning that the reliable technology in 2001 will be much more efficient than the 7000 BTU/kWh model that is used as an example in my direct testimony.

Q: What about OCA's contention that you have underestimated certain costs facing investors in CC units?

A: Mr. Smith states that interest and land costs could be greater than he assumed. In reality, these costs are likely to be much less than assumed, since many CCs can be bolted to existing utility or IPP pads. Mr. Smith also asserts that non-standard features will be reflected in the tradeoffs between plant design and capital cost.[31] From the Exhibit STJ-25 it is clear that my capital cost assumption is consistent with the efficiency (heat rate) I assumed.[32]

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[31] See page 13, lines 24-27.

[32] The text in a section entitled "Competition Driving Costs" which accompanied the data provided in *Gas Turbine World 1996 Handbook*, reads: "global competition among the

Q: Dr. Jones, are there reasons to believe that substantial future savings are possible in the construction of a new CC as compared to the cost numbers presented here?

A: Yes. As suggested by its name, a "combined cycle" generation unit consists of a CT and a steam turbine. In other words, the builder of a CT has the option of adding a steam turbine, heat recovery steam generator, and associated balance of plants, i.e., convert the CT into a CC. Doing so significantly reduces the capital costs associated with the expansion primarily because the combustion turbine has already been bought, the site prepared, the fuel hook-ups in place, etc. Estimates of the savings due to staging a CC with CT units range from 10-15 percent of the capital costs.[33]

As noted, many of the costs cited by Mr. Falkenberg and Mr. Smith are associated with greenfield sites. Even if plants are not

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suppliers of turnkey combined-cycle power stations has in some cases drastically reduced prices; the price of large combined cycle units has declined as much as 40% over the last three to four years; firms are drastically cutting building schedules, sometimes in half; some pre-engineered combined cycles can be installed in under 12 months, cutting interest costs on construction loans and allowing plants to generate revenue earlier." It is worth noting that Mr. Smith asserts that CC/CT equipment costs will rise from existing levels because current market conditions represent a historical low point (page 13, lines 18-19). Of course, in any industry experiencing increased competition and significant technological improvements every day is a historical low point because prices will continue to decrease into the future. There is no reason to expect costs to cease their decline.

[33] 1993 EPRI TAG Report, Exhibit 23.

staged, investors will look to existing sites to place additional capacity in order minimize the cost associated with their projects. For example, PP&L has surveyed several sites for possible CT/CC capacity additions, *including larger sub-station sites not just* existing generation sites. PP&L estimates that its territory contains 10-20 potential sites. Extrapolating to the rest of PJM, there would be dozens of potential sites that are already developed that could be used to avoid the full cost of greenfield expansion. Finally, there are opportunities to increase revenue such as through the sale of waste steam for cogeneration processes.[34]

***PP&L's Use of CC Units as Reliable Incremental Generation* Capacity Was Reasonable and Consistent with Industry Experience**

Q: Please summarize the intervenors' comments regarding the performance assumptions of CC units.

A: Mr. Falkenberg and Mr. Smith raise the issue of plant performance. Mr. Falkenberg refers to a year-old trade press article citing some

[34] Mr. Smith states that his capital costs are optimistic because of additional costs associated with "extended site work such as cogeneration process steam..." (page 14, lines 1-2). Of course, no plant owner would conduct such additional work unless the revenue associated with steam sales covered costs plus the market rate of return. To the extent such opportunities exist, all else being equal, this effect would induce investors to invest sooner in new capacity than I have modeled.

specific problems with one vendor's CC units.[35] His conclusion from a single article is: "I expect that these types of problems will be resolved. However, I am quite skeptical about the extremely optimistic assumptions being made regarding the reliability, O&M costs, and maintenance requirements of these large and highly complex new machines."[36] Mr. Smith expresses a similar level of discomfort when he points out that there is not an "extensive record of industry experience with the advanced equipment that PP&L assumes will provide PJM's CC capacity option...."[37]

Q: Dr. Jones, please address these concerns.

A: The intervenors overstate the importance of the problems noted in the trade press about CC performance. In fact, trade press articles continue to report combined cycle success stories including low capital cost, heat rates well below 7,000 BTU/kWh, and 90%+ availability factors. Perhaps a more balanced review appears in a September 2, 1996 article in *Power Asia*. It reports that "the increasingly rapid technological change which has enabled

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[35] See page 64, lines 11-18.
[36] Page 65, lines 4-10.
[37] Page 17, lines 2-3.

(combined cycle) technology to out-perform its competitors was never going to be achieved without a few problems." Historically, combined cycles have proven to be a reliable technology. Exhibit STJ-26 plots NERC availability data for combined cycle units for 1988 to 1995.[38] As shown by the regression line, availability of these units has been improving.[39] For the years 1994 and 1995, availability exceeds PP&L's 90 percent assumption. At worst, recent concerns are reason to be less optimistic about reports, which have been common for several years, of soon-to-come available units with 6,000 BTU/kWh heat rates.

As noted above, Mr. Falkenberg acknowledges that he expects that the problem that raises his concern will be resolved.[40] Mr. Smith, as I have previously cited, acknowledges that significant cost reductions and technological improvements have occurred. The lack of industry experience with these new units is one reason

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[38] 1996 data is not yet available.

[39] NERC defines "capacity factor" as actual output divided by maximum possible output at dependable net capacity (maximum capacity less power for plant auxiliaries and seasonal variation). NERC defines "availability factor" as available hours divided by total period hours.

[40] Mr. Falkenberg actually provides the cite to more than 20 vendors found in *Gas Turbine World 1996 Handbook*. These vendors offer an array of units that the market will sort through until the industry has a reliable technology and a durable unit. The fact that one vendor was experiencing technical problems is not representative of the choices to be found in the competitive marketplace for combined cycle generation capacity.

why costs in the future will decrease. As builders and operators gain experience, they will discover ways of improving performance and reducing costs.

PP&L's Assumptions Regarding CTs are Consistent with Industry Experience

Q: Dr. Jones, are there major issues associated with your assumptions regarding the capital cost and heat rate for CTs?

A: No. Mr. Smith uses a capacity cost for a new CT of $290/kW, and Mr. Falkenberg does not dispute my estimate of $338/kW.[41] Ironically, Mr. Falkenberg mentions a completed CT in Georgia whose original cost estimate was $378/kW but was completed at a cost of $321/kW, which is 15 percent lower than the forecasted cost and 5 percent lower than my capital cost assumption.[42] Neither Mr. Smith nor Mr. Falkenberg raises issues associated with my heat rate assumptions.[43]

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[41] Mr. Smith, page 13, line 12, and Mr. Falkenberg, page 69, lines 7-8. Mr. Falkenberg notes that he is concerned that my assumption does not fully include the cost of a pipeline and other items.

[42] See page 69, lines 2-4.

[43] The *Gas Turbine World 1996 Handbook* lists numerous of existing CT models that have both heat rates and capital costs that are lower than my assumptions.

Q: Intervenors' witnesses also criticize the fact that you did not explicitly consider adding A&G or O&M costs along with potentially different outage rates when considering the cost of new capacity. How do you respond?

A: These criticisms are either unfounded or misplaced, given the facts about capacity additions.

- A&G cost add-ons are unnecessary when considering the cost of CC or CT units. Since the new units added by EGEAS are likely to be owned by existing utilities or existing IPP's, the incremental A&G costs would be virtually non-existent. For example, PP&L would not have to hire more accountants or other staff to track a CC's costs.
- To the extent that variable O&M costs might change with the addition of new CT or CC units, the direction of that change is not at all clear. Recall that when OCA asked PP&L to rerun EGEAS using its assumptions, new CC units displaced existing fossil units. As a result, O&M reductions at existing fossil units could more than offset any small increase in O&M needed to cover the costs of operating a new CC unit.

- OCA's criticism of PP&L's estimate (p. 16, 17) of fixed O&M costs shows that PP&L's estimate of total O&M is well within the range of estimates referenced by Mr. Smith. Exhibit STJ-27 presents a comparison of PP&L's total O&M estimates for new CC and CT units with sources cited by Smith in answering interrogatories (Question PPL-I-10). Assertions about PP&L's fixed O&M costs are unfounded. It is important to consider total O&M (both fixed and variable), not just fixed costs when looking at O&M.[44]
- As noted, there are numerous references in the trade press to the growing acceptance of CT and CC generation capacity from the standpoint of reliability. More efficient, newly-developed units like those shown in Exhibit STJ-25 will require regular use to demonstrate the best combination of heat rate/cost and reliability by 2002, but that was true several years ago about today's proven plants. Citing speculative concerns about material stress or other operating factors overstates the issue

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[44] Because facility managers tend to categorize their fixed and variable O&M costs differently, there is a wide range of estimates for the O&M components when presented separately. For example, one facility may categorize CT combustor replacement as a fixed O&M cost while another may consider it variable.

and ignores the strong will of the competitive market to sort out possible vendors for the market of 2002.

PP&L's Capacity Price Forecast Is Reasonable

Q: Dr. Jones please summarize the intervenors' comments regarding your capacity price forecast.

A: Intervenors argue that my estimated market-clearing capacity price, in some years, is too low and would produce a negative cashflow for developers, suggesting that the forecast should be raised.[45] OSBA's Mr. Knecht provides a project economics worksheet that claims to demonstrate that my capacity price is insufficient to justify a new combined cycle unit in 2005, and that the price forecast is based on optimal capacity configuration and perfect foresight for demand.[46] Intervenors also question my assumptions regarding shut-downs of existing units and the year that PJM needs new capacity installed in order to meet its installed reserve requirement.[47]

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[45] Smith, page 16, 9-11.
[46] Knecht, page 32, lines 17-18.
[47] Knecht, page 30, lines 13-20, and page 31, lines 1-8, and Smith, page 9-14.

Q: Please address the issues related to your capacity price forecasts being sufficient to make investments in CT and CC units profitable.

A: The idea that investors must have a positive cashflow every year in order to invest is fundamentally flawed. Mr. Smith confuses basic financial economics when he states: "If a developer were to construct a new CT in the time frame and with the capital cost and other characteristics assumed by Dr. Jones, it would lose money in the first two years. A developer does not generally invest to lose money, so Dr. Jones' assumption that new capacity will be built in the time frame he assumes appears questionable."[48] While the demand for electricity in PJM is expected to grow as retail access ensues and the rate cap limits price changes, the current "excess" generation capacity situation in PJM will disappear. Even so, at any point in time, there will be a limit to the amount of new capacity needed to meet that incremental load.

The incentive to be the generator to meet that incremental demand will be strong, with competitors queuing to build capacity sooner rather than later. If an investor were to behave as expected by intervenors, postponing the building of generation until current

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[48] Page 16, lines 8-11.

demand (and price) was sufficient to generate positive profits, competition would insure that investors would most likely find other generator(s) had already installed capacity sufficient to meet current demand.

This phenomenon of racing to invest is a common pattern in highly competitive, capital-intensive industries. The timing of investment is determined by investors weighing initial operating losses against expected profits obtainable in later years, as a result of having foreclosed on a rival's ability to get into the market. For example, a number of studies have shown that firms in industries such as cement manufacturing and chemical processing will build plants that are below minimum efficient scale to minimize these initial operating losses, but still have one foot in the door when profits become positive.[49] Similar industry dynamics are likely to emerge in an unregulated generation market with entrants establishing footholds using CTs and augmenting capacity with combined cycle technology when demand growth materializes.

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[49] See for example, Ronald Johnson and Allen Parkman, "Spatial Monopoly, Non-Zero Profits and Entry Deterrence: The Case of Cement," The Review of Economics and Statistics, 1983; Pankaj Ghemawat, "Investment in Lumpy Capacity," Journal of Economic Behavior and Organization, 1987.

Another outcome for capacity additions in the market would also result in lower capacity prices and the recurrence of the current generation capacity glut. If investors share similar expectations about PJM capacity requirements, then the market might exhibit a propensity for several projects to get underway at the same time. This happens frequently in industries where capacity must be added in lumps. For example, a widely cited series of studies on a number of chemical industries found that "completion of new plants by [incumbents or new entrants] lead to a temporary increase in excess capacity."[50]

Under Mr. Smith's criteria, any capital project that took two years or more to construct, (e.g., an oil refinery, a natural gas pipeline, a steel mill, a semiconductor plant) would never be built.[51] Obviously, this is not the case. In the industrial market, investors do commit capital in advance of cash flows. What Mr. Smith fails to understand is that what matters to an investor is the net present value of <u>all</u> cashflows. For example, Mr. Smith does not include in

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[50] Marvin Liberman, "Postentry Investment and Market Structure in the Chemical Processing Industries," RAND Journal of Economics, 1987, p. 546; "The Learning Curve and Pricing in the Chemical Processing Industries," RAND Journal of Economics, 1984.
[51] The Direct Testimony and Exhibits of Douglas C. Smith, at 16, lines 9-11.

his analysis the revenue that a CT receives from the sale of energy, in addition to the revenue from the sale of capacity.

Q: Dr. Jones, is your capacity forecast sufficient to induce investors to construct combined cycle units?

A: Yes. Exhibit STJ-28 presents the net present value (NPV) calculated using Mr. Knecht's spreadsheet, after adjusting for some minor errors (escalation rates, taxes, *etc.*) for a variety of different combined cycle units listed in *Gas Turbine World*.[52] As the exhibit clearly shows, for these specific CC units, along with many others, the NPV is positive.

Mr. Knecht's analysis for a hypothetical project fails to account for two major issues that would result in significant cost reductions for CC units. These simple modifications make the results Mr. Knecht reports more attractive to investors.

- Mr. Knecht fails to account for the fact that, in reality, there are a variety of cost-saving or revenue generating options open to investors in CC units. As I noted elsewhere, generators could sell steam, they could site units on existing

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[52] Exhibit RDK-2, Schedule 5.

"pads", etc. Significant cost-savings would results from developers "expanding" an existing CT into a CC, rather than engaging in greenfield construction. This saves the cost of the turbine which could be appended to the steam unit.

- More importantly, however, Mr. Knecht does not account for technological improvements and cost reductions that I describe above.

To demonstrate that many different types of CC units are potentially profitable investments, I adopted Mr. Knecht's "project economics" approach and his spreadsheet, replacing some of his variables with the updated data for the CC units listed in Exhibit STJ-28. The results, having added Mr. Knecht's working capital, and decommissioning costs, appear in column NPV#1 of Exhibit STJ-28 with a detailed example shown in the spreadsheet listed as Exhibit STJ-28-a.[53] A similar set of results appear in column NPV #2 of Exhibit STJ-28 and Exhibit STJ-28-b where I have used

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[53] The example plant in the spreadsheet is composed of three Asea Brown Boveri GT 11N2, 133 MW gas turbines, a single 172 MW steam turbine, and a dual pressure heat recovery steam generator with no reheat cycle. These units were introduced to the market in 1993 and have had some time to "mature". Hence, this plant is an example of an uncomplicated installation that has been commercially available for four years. In that regard, *it is a conservative* example to use as a plant for 2002.

alternative assumptions in the spreadsheets. In all instances, the technology that is here today (as listed in *Gas Turbine World*) will have had several years to prove itself by 2002. I am therefore conservative because I do not account for technological improvements over the course of the next several years. It is these units, not the 7000 BTU/Mw units I used in my example, that offer attractive returns for future CC investments.

Q: Dr. Jones, does your forecast assume perfect foresight by developers of new capacity?

A: No. As my capacity forecast clearly demonstrates, I forecast prices that rise rapidly to $50/kW-year by 2002 in response to tight capacity and high demand-based pricing. The anticipated capacity response will then decrease market-clearing prices to $44/kW-year in 2005. After that, I simply increase prices in line with inflation. This rapid rise, overshoot, and return to competitive equilibrium is meant to capture Mr. Knecht's point on this issue.[54]

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[54] See Knecht, page 30, line 9.

PP&L's Assumptions Regarding Planned Retirements Are Reasonable

Q: Dr. Jones, what issues do intervenors raise regarding unit shutdowns?

A: Mr. Smith and Mr. Knecht disagree with my assumptions regarding the timing of unit shut-downs, but they provide no analysis to support their criticisms.[55] For example, OCA's Mr. Smith's assertion that "To the extent that some 'economic retirements' actually occur, there will be additional upward pressure on capacity and energy prices relative to his analysis, and to the market price analysis of PP&L and PECO" is not correct.[56]

Q: Do you have any comments regarding intervenors' witnesses' allegations about retirements/closings?

A: Yes. I have two comments.

- As I noted earlier when demonstrating the results of OCA's requested rerun of EGEAS, new CC units will tend to displace existing fossil units. Adding efficient CC capacity in place of

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[55] Smith, page 19, lines 1-8, and Knecht, page 30, lines 13-20, and page 31, lines 1-3. Mr. Smith flat out states that he "did not test the economic viability of the existing generation units in PJM."
[56] Smith, at 19, lines 6-8.

less efficient generation lowers, rather than raises energy prices as intervenors seem to suggest.

- PP&L's Mr. Krall[57] explains that the deactivation dates for PP&L's plants as used in EGEAS are those approved by the Commission in PP&L's most recent base rate proceeding. Further Mr. Krall notes that the deactivation schedules for PP&L's existing units are consistent with the depreciation schedules in PP&L's January, 1997 rates.
- Mr. Krall also provides testimony about the consistency with PP&L's embedded unit "life extensions" and the relevance of additional capital expenditures to the Act.

On the basis of these facts, I conclude that the data used in EGEAS regarding plant retirements/deactivations is not only reasonable, but consistent with the information on file with the Commission and with PJM system planning documents. The introduction of alternative unit retirement schedules would constitute sheer speculation.

[57] Rebuttal Testimony of Douglas A. Krall, Statement No. 3-R.

Ancillary Services

Q: Dr. Jones, please summarize the intervenors' comments regarding ancillary services.

A: Several intervenors argue that I do not adequately include ancillary services in my analysis. In particular, Mr. Smith notes: "Although Dr. Jones models a spinning reserve requirement for PJM, he does not attempt to determine the revenues that generators providing spinning reserve in a given hour would receive. Dr. Jones does not model any other ancillary services."[58]

Q: Dr. Jones, please address Mr. Smith's concerns.

A: Once again a "concern" is raised with little or no analysis to support it. Mr. Smith confuses additional revenues that PP&L may receive from the provision of ancillary services with a contribution to stranded cost. In other words, Mr. Smith implies, without any analytical support, that PP&L's stranded cost estimate ought to be reduced dollar-for-dollar due to its provision of ancillary services. This simply defies logic since the provision of any service, at the

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[58] Smith, page 8, lines 21-24 and page 30, lines 7-9.

margin, increases incremental cost.

Q: Dr. Jones, please describe the effect of ancillary services on the market price of energy and PP&L's stranded costs.

A: Let me first identify which ancillary services are relevant to generation and estimates of market-clearing energy prices. In the category of operating reserves, there are three subcategories. The first, spinning reserves, refers to units that must expend fuel (start-up costs and no-load costs) in order to provide spinning reserve service. In a competitive market, the marginal spinning reserve unit would recover its costs associated with providing this service. In addition to spinning reserves, there are other operating reserves such as ten-minute non-spinning reserve and thirty minute non-spinning reserve.

All other ancillary services, such as scheduling/dispatch and area regulation services (frequency and voltage support), will be provided under transmission services and a regulated framework. I would not expect these other ancillary services to have a material impact on market-clearing prices.

Q: Dr. Jones, how did you account for spinning reserves?

A: I specified in EGEAS a spinning reserve requirement. As a result, EGEAS ensures that sufficient spinning reserves exist for every hour. In order to meet this requirement, EGEAS adjusts its energy dispatch so that sufficient units capable of providing spinning reserves are on line.

Q: Dr. Jones, have you made any estimate of the impact on the market-clearing price for energy in the absence of a spinning reserve requirement?

A: Yes. In an effort to demonstrate how small intervenors' claimed flaw in my testimony would have been had I not included spinning reserves, I separately ran EGEAS to generate an alternate market-clearing price for energy. The alternative market-clearing price estimate shown on a year-to-year basis appears in Exhibit STJ-29. The impact of spinning reserves on market-clearing prices for energy is to increase the energy price by $0.20/MWh. Again, while my market-clearing prices found in Exhibit STJ-7 include this additional $0.20/MWh, the estimate still serves to indicate the *de minimis* nature of intervenors' allegations on market prices.

Q: Dr. Jones, will competitive ancillary services provide a significant amount of revenue to PP&L?

A: No. Revenues from operating reserves, not including spinning reserves, are unlikely to contribute significantly to stranded cost recovery. The hourly non-spinning reserve requirements in PJM are approximately 2500 MW, a small portion of the capacity installed in PJM capable of providing this service. Because PJM requires sufficient capacity to meet its reserve requirement during peak load, after accounting for planned and random maintenance outages, sufficient reserves exist to meet PJM's non-spinning reserve requirements. As a result, the expected revenue from these non-spinning reserves are likely to be low in a competitive market. Moreover, only 380 MW of PP&L units are capable of providing non-spinning reserves.[59]

Q: Dr. Jones, are there other ancillary services that might result in additional, material revenues to PP&L?

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[59] The data were supplied by PP&L's system engineers. For example, the Company maintains 130 MW of quick start reserves and 250 MW of secondary and other reserves.

A: The only other ancillary service that might result in additional revenues to PP&L is area (frequency and voltage) regulation. These ancillary services are provided at cost, so even if the revenues were material, which they are not, their contribution to stranded cost would be minimal.

Q: Dr. Jones, for the sake of argument, assume that ancillary services would provide a material level of net income for generators. What are the implications for the forecasted price of capacity?

A: If the provision of ancillary services provides a material amount of net income for generators, the market-clearing price for capacity would decrease. This income stream, similar to the margin made on energy sales, would induce builders of capacity to build at lower expected capacity prices because their costs would be covered by this additional stream of net income. Thus, even if the intervenors are correct, the result is that the price of capacity must be revised downward.

Probabilistic Modeling

Q: Please summarize Mr. Falkenberg's criticism of the method EGEAS uses to calculate expected prices and revenues.

A: Mr. Falkenberg states that EGEAS "will significantly understate prices during periods of lower loads...by an amount that is not possible to quantify"[60] because EGEAS calculates expected prices as opposed to calculating expected revenue directly on a plant-by-plant, hour-by-hour basis.

Mr. Falkenberg's criticism is inconsistent with the examples he presents and, like his heat rate analysis, inconsequential even if assumed to be correct. More importantly, his analysis, if it is to have any validity, ignores the very pressures competition brings to bear on the situation he describes.

Q: Please review Mr. Falkenberg's own conclusions regarding his criticism.

A: Mr. Falkenberg acknowledges that his criticism does not apply to baseload units. He states: "For submarginal (or baseload) units,

[60] Page 43, lines 7-9, and page 47, line 3.

this is not a problem."[61] It is worth noting that PP&L units are primarily base load units, a fact which the intervenors have cited in other contexts in their attempts to discredit PP&L's forecast. Mr. Falkenberg also acknowledges that his point does not have a significant impact during the very highest load hours of the year.[62]

Q: Please critique Mr. Falkenberg's examples that he uses to make his point.

A: Mr. Falkenberg's examples leave the mistaken impression that the additional *expected* revenue he is describing is significant. When this additional *expected* revenue is calculated, nothing could be further from the truth.

Mr. Falkenberg has one example in which the load is 47,000 MW. The probability of this occurring in 2005 is less than 0.1 percent.[63] He then assumes that three nuclear units are forced out of service. The probability of this occurring is approximately 21 percent.[64] The probabilities of these events occurring are assumed

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[61] Page 42, lines 14-15.
[62] Page 43, line 5.
[63] I choose 2005 for this analysis because in earlier years the probability of this load was for all practical purposes zero.
[64] Assuming independent outages with a probability of 15 percent as Mr. Falkenberg does.

to be independent of one another. If this were the case, which it is not, the probability that both these events occur, is the product of the two numbers, which is (0.001)*(0.21) or 0.00021. In his example, the market price jumps from $60/MWh to over $70/MWh. The expected additional revenue for the CT Mr. Falkenberg uses in his example is ($70 - $60)/MWh *0.00021 or $0.0021/MWh.

The message in this example is that in order to get a large increase in the market price, from $60/MWh to $70/MWh, Mr. Falkenberg has to assume high load conditions, which is very rare by definition. Mr. Falkenberg presents another example using a mid-cycle unit at a lower load level.[65] In this case the load level is approximately 44,000 MW, which occurs approximately 0.3 percent of the time in 2005. Again assuming three nuclear units are forced out, then the probability of this event occurring is 0.00063 percent (0.003*0.21). The change in the hourly market clearing price according to Mr. Falkenberg is $3/MWh. The expected increase in revenues is $0.0019/MWh.

These two examples illustrate how inconsequential Mr. Falkenberg's point is once the probabilities associated with his

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[65] Page 46, lines 5-10.

examples are included. A large run-up in prices is irrelevant if its probability is so small that its effect on expected revenue is negligible. In addition, during lower load levels, additional outages have little effect on market prices given the "flatness" of the supply curve. Over the most likely demand range, 17,600 to 29,000MW, the marginal cost increases approximately $5/MWh.[66] In order to achieve a $5/MWh increase in prices over a 10,000 MW range, this is equivalent to the largest 11 units being out of service.

Q: Dr. Jones, you mentioned that Mr. Falkenberg fails to incorporate the effects of competition in his simple examples. Please explain.

A: Let me correct the analogy that Mr. Falkenberg uses. He makes the analogy to a game of dice, in which the outcome of each roll of the die is independent of the outcome from the previous roll. In competitive markets, however, suppliers and buyers will respond to changing market conditions and these responses will have the effect of reducing prices. In other words, buyers' and suppliers' actions are not independent, and the result of their interdependent actions is to drive prices down. If several large units are forced out,

[66] For 1999, approximately 66 percent of the time, load is within this range.

unit owners who were preparing to conduct planned maintenance will delay their plans to take advantage of high prices, thereby reducing the price spike inherent in Mr. Falkenberg's analysis. Other competitive responses include increased imports into PJM, reduction in load, reduction in the time that plants are unavailable, and reduction in forced outage rates. Mr. Falkenberg, in his simple examples, is ignoring the competitive forces that will act to reduce both the price spikes and the probability of those spikes occurring. Further, Mr. Falkenberg makes several obvious errors that result in overstating the market price of energy and capacity. These errors and others are described in the Rebuttal Testimony of Jonathan S. Falk on behalf of PP&L.

Effect of NO_X Allowance Prices on PP&L's Revenue

Q: In your direct testimony, you state that you did not include the effect of NO_x prices on PP&L's revenue because of the lack of credible techniques to establish these prices and the fact that their impact is likely to be very small. OCA's Mr. Smith asserts that NO_X considerations will likely "increase market generation prices by less than $1/MWh on average. Even an increase of $0.5/MWh, however, would raise PP&L's net revenues significantly".[67] How do you explain this difference?

A: While NO_X allowances will increase the incremental cost of generation for PP&L's affected units, Mr. Smith appears to overstate the importance of NO_X in increasing the company's net revenues for two reasons.

- He bases his estimate of an allowance price on estimates found in testimony done on behalf of PECO (Docket R-00973877) which places their value from $1,000 to $1,500 per ton of NO_X. While I have no knowledge of the underlying assumptions that produced these estimates, they appear to be based solely on the capital expense to offset NO_x emissions. Historical experience shows this methodology can lead to serious overstatements of compliance costs. [68]
- Mr. Smith appears to overstate the importance of NO_X allowance prices in calculating changes in the market-clearing price of generation. The impact on market-clearing price will

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[67] Smith, page 24, lines 2-4.

[68] Estimates of allowance prices based on the capital cost of retrofitting generation plants to remove SO_2 turned out to be vastly higher (about $1000-$2000/ton) than the current trading price of those allowances (about $100/ton).

depend on the evolution toward less NO_x emitting gas-fired generation for the marginal generation plant. Today's plant mix that is likely to be "at the margin" when it comes to setting market prices may not be representative of the marginal plants later in the transition period.

Q: How does NO_X emission trading affect the market-clearing price of generation and generator revenue from electricity sales?

A: NO_X emission trading will change the market-clearing price of generation when the highest price unit that succeeds in being dispatched emits NO_X and is subject to a cap-and-trade market where such emissions are equivalent to "spending" an allowance. That plant's NO_X expenditure is a function of its emission rate, heat rate, and allowance price. For example, suppose the last unit dispatched is a combustion turbine with a heat rate of 12,000 BTU/MW, an emission rate of 0.1 lb. Of NO_X per MMBtu, and allowance prices were $200 per ton (or $0.1 per lb.). Its rate of NO_X expenditure would be $0.12 per MW (or 0.1 x 0.1 x 12). The effect of NO_X allowance costs on the yearly net revenue of generators in the aggregate would be a function of the average

NO_X expenditure rate of the last unit dispatched. Further, since trading programs for NO_X apply only during part of the year (the "ozone season," which runs from May to September), allowance costs would be zero throughout most of the year.

Q: What will be the structure of a NO_X trading program in the PJM region during the transition period?

A: The PJM region is included in the Ozone Transport Region (OTR). Nearly all generators in the OTR will be subject to a yearly cap on NO_X emissions of about 220,000 tons beginning in 1999. About 130,000 of those tons will be allocated to Pennsylvania, New Jersey, and Maryland. The cap (of which the PJM region will receive about 80,000 tons) in 2003 will be reduced by about 35 percent. The cap applies to a five month ozone season running from May to September.

Q: Is it possible to accurately calculate how the NO_X trading program in the OTR will affect generator revenues?

A: It is not possible to precisely calculate how the trading program will affect generator revenues, although the magnitude of the impact can be determined. "Best guesses" are difficult because major issues like specific trading rules have not been resolved in all areas. Further, generators need not combat this problem by incurring allowance costs. As was the case in the SO_2 allowance market, some generators avoid the need to incur costs by modifying their behavior (i.e., plant/fuel use) to satisfy emissions limits.

Q: Can you quantify some estimate of NO_X allowance costs, recognizing the tremendous uncertainty with regard to the numbers?

A: By estimating the emission rate and allowance prices, we can gain some understanding of the NO_X allowance market's impact on generation revenues. I estimate that the average emission rate in PJM will be about 2.0 lbs./MWh.[69] The emission rate of units setting the market price (the most expensive units dispatched) will, on average, likely be higher given that NO_X-free nuclear and hydro capacity constitutes base load generation. However, over time,

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[69] The average allowable emission rate will be higher than 2.0 lb./MWh from 1999 to 2002 and lower than 2.0 lb./MWh beginning when the cap is tightened in 2003. For example, PJM will receive about 80,000 allowances in 2003. Assuming generation of about 97,000 GWh during the five month ozone season for that year, average allowable emission rates would be about 1.65 lb./MWh. Actual emission rates in the region will vary due to interstate trading of allowances and other factors.

even this factor will be offset by the substitution of low emitting natural gas plants for existing mid-load and peaking capacity, particularly late in the transition period when the NO_X cap is tightened. With all these conditions, and assuming allowance prices of $200 to $500 per ton, I estimate that NO_X allowance costs will add somewhere between $0.05 and $0.30 per MWh to the yearly average price of electricity.[70] As discussed below, this number is small and may apply only to the "out-years" of the transition period, lessening the present value impact of NO_x allowance costs on any estimate of PP&L's stranded costs.

Q: Why do you assume an allowance price lower than that used by PECO?

A: Recent studies by the EPA (EPA 1995) and The Ozone Transport Assessment Group (OTAG 1996) identify a large number of NO_X reduction technologies suitable for plants in the OTR with costs ranging from $10 to $1,000 per ton. That would put NO_x reduction costs below PECO's estimates. While I have not conducted a

[70] For example, we would expect an increase of about $0.10/MWh with an allowance price of $200/ton, an average emission rate from the unit setting the market price of 2.2 lb./MWh and 44 percent of generation occurring during the ozone season.

detailed study matching low cost reductions to the level required in the OTR, it appears that the required reductions in the OTR will not force the use of more expensive technologies, especially when given the flexibility afforded by a cap-and-trade program.

Q: Why do cap-and-trade programs produce costs that are less than those predicted based on engineering studies of the cost of reducing emissions?

A: Cap-and-trade programs harness the competitive market by giving equal incentive to each generator to lower emissions in whatever way is least expensive. Operators are not required to reach a certain rate or employ a particular technology. They only need to possess sufficient allowances to cover their emissions and operators are given credit for any "overcontrol". Finally, cap and trade programs stimulate innovation that lead to control methods not possible under traditional "technology-forcing" standards.

Q: Does experience with emissions trading to date support the assertion that allowance prices typically fall well below early estimates?

A: Yes. The national SO_2 allowance trading program is well known. As I noted, the early forecasts set allowance costs at $1000-$2000 per ton. As the program developed, prices steadily fell, reaching a low of about $70 per ton last year.

On the state level, the RECLAIM program limits emissions of both SO_2 and NO_X in Southern California, a region widely regarded as having the worst and most persistent air pollution problems. Early estimates of RECLAIM trading prices for NO_X were in the tens of thousands of dollars (CEC 1995). While the program is still fairly new, the RECLAIM program experience provides a point of reference for those trying to track prices in NO_X trading for OTAG, since vintage 2000 through 2010 allowance prices have fallen to around $2,000 per ton, well below early expectations.

Q: The Environmentalists' witness Mr. Schoengold alleges that PP&L's plans do not include expenditures to upgrade existing plants to meet NO_X performance standards.[71] Is that true?

A: No. As explained by PP&L's Mr. Krall, PP&L plans include $230 million to upgrade for SCR and SNCR systems for NO_X reduction.

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[71] Prepared Testimony and Exhibits of David Schoengold, at 36.

PP&L's Non-Utility Generator Capacity Factors Are Reasonable and Consistent with Industry Trends

Q: Intervenors' witnesses criticize PP&L for using NUG capacity factors near 90%. How do you respond?

A: I took the capacity factor for NUGs from data provided by PP&L's Mr. Krall. In his Rebuttal Testimony, Mr. Krall states that PP&L used recent operating levels of NUGs in its service territory as the basis for the capacity factor. Mr. Krall's reasoning was based on the actual year-to-year performance of the units and the economic incentives facing owners of these units. I found nothing wrong with these assumptions.

Intervenors Use of a 75% Nuclear Capacity Factor is Unsupported by Facts

Q: Dr. Jones, do you have any other comments regarding the assumptions used by intervenors' experts that affect their estimated market-clearing prices?

A: Yes. I am concerned about intervenors' use of a nuclear capacity factor that is unsupported when tested against historical information that clearly indicates higher nuclear plant capacity factors. The use of a nuclear capacity factor that is too low would unnecessarily increase forecasted market-clearing energy prices.

Q: You have assumed 78 percent availability factors in modeling nuclear units in PJM. These are somewhat higher than assumptions used by intervenors. For example, Mr. Smith uses 75 percent (p. 21, 27-28). Which value do you feel is more appropriate?

A: Nuclear unit availability of 78 percent is conservative. Nuclear unit availability has improved considerably in the United States in the last 10-15 years and is expected to continue to improve. Exhibit STJ-30 shows historical availability factors for nuclear units in the United States from 1982 to 1995. In that period, availability factor has improved steadily from about 65 percent to nearly 80 percent. Mounting experience in operating nuclear units has led to better management practices and fewer forced outages. For example, units experienced nearly 900 hours of forced outage in 1991. This number dropped to below 700 hours in 1995.

Moreover, NERC forecasts show that this trend is expected to continue. Exhibit STJ-30 plots forecasted capacity factors to 2006 (actual capacity data are shown from 1991 to 1996). Because nuclear units are typically run at full load whenever they are available, anticipated capacity factors should closely mirror, though be slightly lower than, anticipated availability. NERC forecasts suggest availability factors of at least 85 percent should be expected for the next decade. Thus, 78 percent is a somewhat conservative estimate of future nuclear availability.

UNDER RETAIL COMPETITION PP&L WILL LACK MARKET POWER

Q: Are you familiar with the market power problems raised by intervenors' witnesses Mr. Biewald for the Environmentalists, Mr. Johnstone for Mid-Atlantic Power Supply Association, and Dr. Mayo for Enron Power Marketing Inc.?

A: Yes. I have read these witnesses' allegations that PP&L will have vertical and horizontal market power to affect market prices in PJM.

Q: What experience do you have in assessing market power?

A: I have filed testimony before the Federal Energy Regulatory Commission, state agencies, and courts on market power issues. Most recently, I filed the market power analysis on behalf of PP&L's application to sell energy and capacity at market-based rates (FERC Docket No. ER97-3055-000, filed May 23, 1997).

Q: Has the Federal Energy Regulatory Commission made a determination based on PP&L's request to charge market-based rates in PJM?

A: Yes. The Commission accepted for filing PP&L's proposed market-based rates tariff in its Order of July 17, 1997.

Q: Is part of what the Commission considered when approving PP&L's request for market-based rates relevant to the rebuttal of Intervenors' market power allegations in this proceeding?

A: Yes. According to the Commission's Order of July 17, 1997 and in keeping with the Commission's new merger guidelines issued on December 18, 1996, FERC allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. This requires that PP&L provide, to the satisfaction of the Commission, an open-access transmission tariff to mitigate transmission market power issues, a specific statement regarding its treatment of affiliates, identification of any other barriers to entry/reciprocal dealing, a variety of statements about the information the Company will make available through reports/filings, and a study to demonstrate that PP&L lacks generation market power in the relevant market. All of this information was supplied in the filing of May 23, 1997.

Q: In light of this finding by the FERC, how do you respond to the various intervenors' allegations regarding market power in this proceeding?

A: PP&L witness Professor Joseph P. Kalt responds to the allegations raised by Enron's Dr. Mayo. I would simply point out that to the extent Dr. Mayo's allegations rest on the empirical evidence showing that PP&L lacks market power, the market study that I filed in support of PP&L's application for market-based rates provides a definition of the relevant geographic and product markets along with a variety of measurements for market power under different market conditions. I recognize that the definition of the relevant geographic market in the study filed at FERC as all of PJM is currently affected by the fact that not all of the states containing PJM utilities have ordered retail access. If a company, PEPCO for example, wants to sell into Pennsylvania's retail market after customer choice takes effect, it is required to satisfy the Act's reciprocity provision. However, other states (e.g., New Jersey) are moving rapidly toward retail competition, minimizing this provision in the Act. In what follows, I have turned my attention to the testimony of intervenors' witnesses Mr. Johnstone and Mr. Biewald.

Q: What is the scope of the issues raised by these witnesses?

A: Intervenors' witnesses cite a variety of vertical market power concerns. Among those concerns are favoring affiliates in buy/sell decisions, manipulating access to transmission assets, failing to provide equal access to all competitors for metering, billing and other services currently under control of PP&L, favoring affiliates with better service, adding capacity or otherwise tailoring investment to meet the needs of affiliates, cross-subsidy of non-regulated affiliates and providing affiliates with market-sensitive information at the expense of all competitors. Intervenors' witnesses cite a variety of horizontal market power issues as well involving the level of PP&L's generation rates (predatory pricing of energy and capacity) and the possibility that PP&L might withhold capacity to benefit from higher market-clearing prices when load is high.

Q: How do you respond to the vertical market power complaint?

A: As a general policy matter, structural remedies designed to eliminate vertical market power should be imposed only when the force of competition will be insufficient to prevent the exercise of such market power. Intervenors assert that PP&L's vertical integration into metering will somehow prevent competitors from successfully competing with PP&L for retail customers. It has long been recognized that an effective means of entry into any industry is to build a better product or deliver more value to the customer than the incumbent is providing. In the instance of metering, competing power marketers can nullify any advantage PP&L may currently enjoy by owning meters that are in-place merely by offering metering alternatives that enable customers to capitalize on these lower energy charges. A particularly germane example is provided by telephony.[72]

In Japan, the two largest phone companies are DDI and NTT. As in the United States, a wide range of prices exists for different types of calls. DDI offered lower prices for many calls, but

[72] The example that follows is drawn from Adam Brandenburger and Barry Nalebuff's book entitled, "Co-opetition," 1996.

whether they offered lower prices overall depended on the calling pattern of a particular customer. For quite some time it has been possible for customers to route calls over whichever carrier offered a lower rate for that particular call, but this call-by-call switching required the caller to enter a four-digit prefix before placing each individual call. Rather than merely complaining that NTT's high market share from earlier more restrictive regulatory regimes was somehow unfair, or that DDI wasn't able to win customers in spite of its lower prices, DDI did what the economics of competition would predict: they innovated. DDI developed a chip that goes inside the phone and automatically routes each call over the cheapest carrier for that particular call.

Not surprisingly, there has been no shortage of companies willing to sell these "chip phones" since they can advertise that the phones will pay for themselves. In the end, competition led to lower prices for customers and an entrant with lower prices was able to compete successfully with the established incumbent. It is therefore difficult to understand how ownership of meters will enable PP&L to keep out competitors offering lower prices or better service. As a case in point, consider the fact that Cellnet, a company with the world's largest installed base of advanced metering devices in the world, is neither for nor against the unbundling of metering services.[73] They recognize that in a competitive world, who does the metering is irrelevant. The most efficient competitors will prevail.

Intervenors' witness Mr. Johnstone also asserts that PP&L's unique ability to offer customers a single bill will somehow enable it to exercise vertical market power. In this instance, a cursory look at the list of competitors who have expressed interest in selling power is enough to dispel that notion. In fact, some firms have already announced their intention to bundle electricity with other services such as water, telecommunications, financial services, and a host of others.[74] With such competition-induced product innovations it is difficult to imagine how PP&L's ability to offer a single electricity bill presents an advantage that can be translated into exercisable market power.

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[73] See Comments of Cellnet Data Systems in re: State of Maryland Public Service Commission, Inquiry into the Provision and Regulation of Electric Service, case no. 8738.
[74] See for example, "UtiliCorp and PECO, Aided by AT&T, To Launch One-Stop Utility Service," Wall Street Journal, June 24, 1997.

In the instances emphasized by Mr. Johnstone, namely metering and billing, the force of evidence indicates that PP&L does not have vertical market power. In addition to the force of competition, this lack of vertical market power is further assured by the rules on comparable service (regarding, among other things, access to information) already in place as stated in Order 889 and as promulgated by the PAPUC. Further, PP&L has filed testimony in this proceeding regarding its proposed Code of Conduct which speaks to the issues raised by Mr. Johnstone. Given the ground rules in place, any attempt by PP&L to exercise vertical market power will be defeated by the actions of profit-seeking competitors as described in the foregoing paragraphs.

Q: How do you respond to intervenors' allegations about horizontal market power?

A: The PAPUC can consult the filing and FERC's findings in PP&L's application for market-based rates for a detailed examination of the possibility of horizontal market power. As noted, the tests used in that study are consistent with the FERC's Merger Guidelines and the Department of Justice, *Horizontal Merger Guidelines*. These regulatory rules protect competitors against horizontal market power in the event of a merger and the tests are applied in the instance where a utility petitions for market-based rates.

The intervenors make much of the fact that the HHI of PJM, as they have incorrectly calculated it, indicates a "moderately concentrated" market that merits further examination using their proposed methodologies. Their assertion that a calculated HHI between 1000 and 1800 impels further market power analysis of PJM is unfounded. In fact, the Department of Justice's 1986 report on competition in the oil pipeline industry suggests that markets be presumed sufficiently competitive for market-based pricing if the HHI is below 2500.[75] In a recent article, the DOJ's director of economic research specifically opined that in the case of electricity, the presumption of reasonable market-based pricing would rarely be overcome in markets with HHIs below 2500.[76] DOJ recognizes that the cost of choosing an artificially low market power threshold, as the intervenors have done, would be the continuation of a

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[75] Oil Pipeline Deregulation, U.S. Department of Justice, 1986.
[76] Gregory Warden, "Identifying Market Power in Electric Generation," Public Utilities Fortnightly, February 15, 1996.

regulatory regime that, by some estimates, reduces social welfare by $100 billion per year nationwide.[77]

Even if the intervenors had chosen a more appropriate HHI benchmark, their HHI calculation for the PJM market is flawed due to their fundamental misunderstanding of the market power test. As spelled out in the Department of Justice 1992 *Horizontal Merger Guidelines,* on which the intervenors base their assertions, proper market power analysis must consider the ability of buyers to access alternatives that could enter the relevant market in response to attempts by incumbents to exercise market power. As pointed out by the FERC "...the calculation of an HHI or any market concentration measure must be grounded upon an informed understanding of the institutional, regulatory and structural realities of the markets that are being examined."[78]

Intervenors argue that the short-run demand for spot electricity is relatively inelastic. However, such a contention overlooks the fact that most of the purchases in the PJM Interchange Energy Market will be made by entities that are

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[77] Tabors Caramanis and Associates, "Unbundling the U.S. Electric Power Industry: A Blueprint for Change," 1995.
[78] Northeast Utils. Serv. Co., 56 FERC ¶61,269 at p. 62,008 (1991).

required by regulation to be self-sufficient (in terms of peak load plus reserve requirements). These entities retain the ability to respond to attempted exercises of market power by increasing the extent to which they self-schedule. Bilateral contracting represents another means of buyer substitution if sellers attempt to raise prices in PJM.

Intervenors also unrealistically restrict the population of sellers to include only current owners of generation capacity in PJM. Their methodology completely ignores section 1.521 of the *Horizontal Merger Guidelines* entitled "Changing Market Conditions" which states that: "Market concentration and market share data of necessity are based on historical evidence. However, recent or ongoing changes in the market may indicate that the current market share of a particular firm either understates or overstates the firm's future competitive significance."[79] Given the number of sellers clamoring to become players in the PJM area (membership in PJM's Interconnection Association now exceeds 40 entities), it strains credulity to argue that the PJM market is not becoming more open to outside entrants. Therefore traditional HHI

[79] Horizontal Merger Guidelines, U.S. Department of Justice, 1992.

measures (based solely on historical market conditions), like those misapplied by Mr. Biewald, overstate the future degree of market concentration in PJM.

For example, the fact that PP&L currently has 100% market share with respect to retail distribution is meaningless if customers can access alternative suppliers as I have described. The availability of wheeling as promulgated in Section 211 of the Energy Policy Act Amendments and the rise of alternative generation resources makes statistics such as the 100% retail share increasingly meaningless.

In short, the intervenors' concerns over the exercise of horizontal and vertical market power are unfounded and appear to be driven by their misunderstandings regarding the appropriate way to calculate market concentration, their selection of an inappropriate benchmark by which to evaluate market concentration and their ability to ignore the impact of competition on the market for electricity.

CONCLUSIONS

Q: Does this conclude your rebuttal testimony?

A: Yes, it does.

EXHIBIT STJ 9

Impact of Competition
Lessons from Other Formerly Regulated Industries

- Deregulation followed by industry restructuring has not been a "zero sum" game.

    - The percentage decline in real prices charged consumers has been significant.

        * Railroads - down 44% since Stagger's Act (1980).
        * Trucking - down 56% since 1977.
        * Airlines - down 29% since 1977.
        * Natural gas - down as much as 57% since FERC *Order No. 436*.

    - Measures of "public welfare" have increased despite replacing regulatory standards with competitive market forces.

        * Competitive market forces discipline sellers to offer quality-enhancing services in order to attract customers.
        * Competitive market forces discipline sellers to constantly review and increase the number of service offerings.

- The process of industry restructuring has aligned prices, incremental costs, and investor returns in formerly regulated industries.

    - Variable costs, like O&M, have declined.

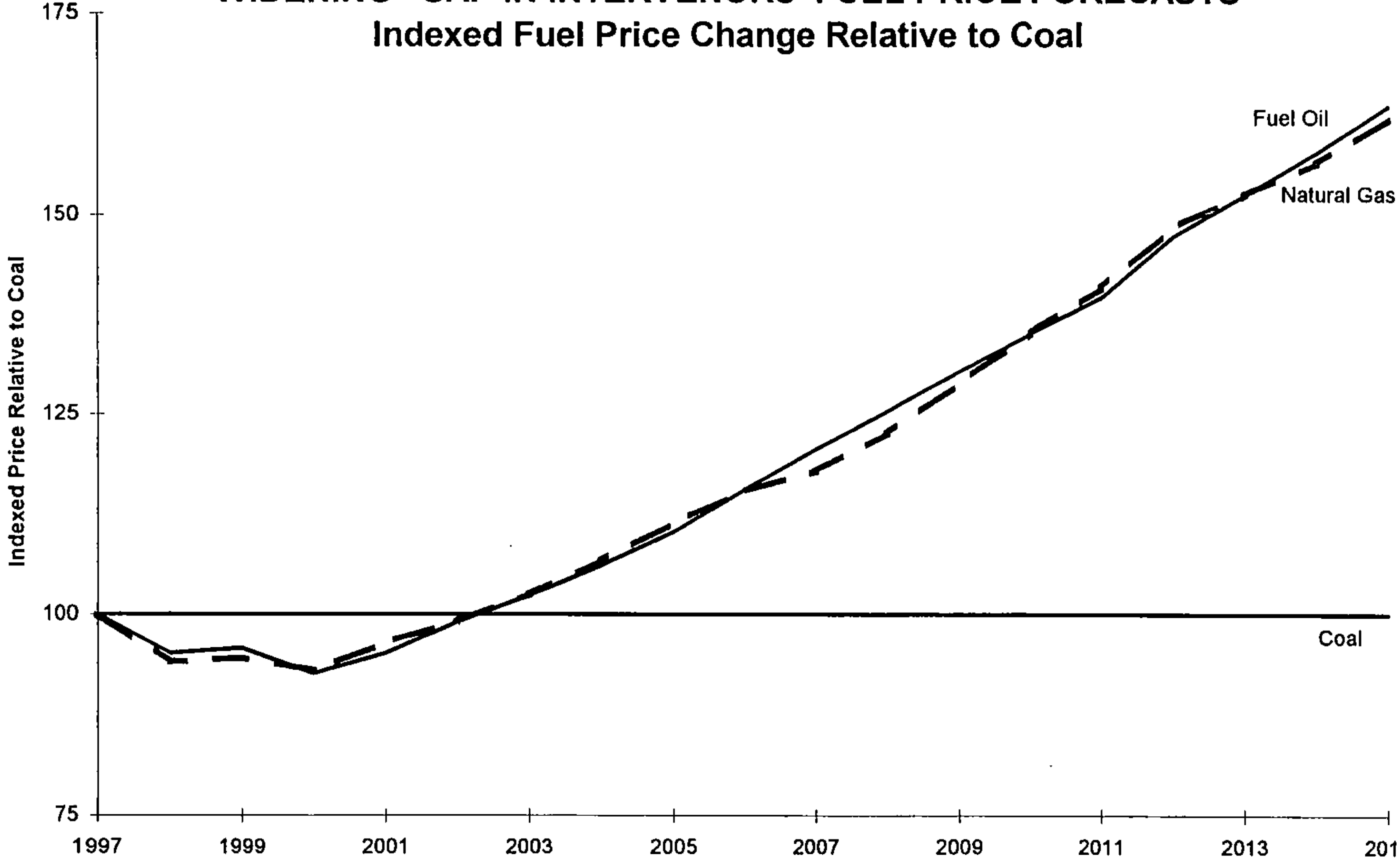
        * Technology has increased, lowering incremental costs.
        * The use of financial instruments has reduced the differential between spot versus term prices.

    - Return on capital is competitive. Formerly supra-normal, or anemic returns have adjusted to market rates.

Source: R. Crandall and J. Ellig, "Economic Deregulation and Customer Choice: Lessons for the Electric Industry," Center for Market Processes, George Mason University.

EXHIBIT STJ 10

WIDENING "GAP IN INTERVENORS' FUEL PRICE FORECASTS
Indexed Fuel Price Change Relative to Coal



Sources: DRI Fuel Escalation Rates from OCA's Exhibit DCS-6; base-year price from PPLICA Statement No. 2 Exhibit RJF-2.

Exhibit STJ-10

EXHIBIT STJ 11

S. T. Jones
(Supplemental 6/27/97)

Pennsylvania Power & Light Company
Response to Interrogatories of the
Office of Consumer Advocate, Set VIII
Dated May 13, 1997
Docket No. R-00973954

Q.1. In order to isolate methodological differences and minor input differences from differences in results due to major inputs, please use your market price model and methodology to estimate PJM market prices utilizing the following input assumptions:

a) Fuel prices (Electric Generators, Middle Atlantic) presented in the EIA Annual Energy Outlook 1997 (escalated to nominal dollars by the EIA GDP deflator, as presented below);

b) Adjustment of the EIA coal prices for higher sulphur content by a negative 15%;

c) A capacity factor or 75% for nuclear units;

d) Market capacity prices as follows: \$17/KW/year in 1997; \$30/KW/year in 1998; and \$43/KW/year in 1999. From 2000 forward, the 1999 price should be escalated at the EIA's forecast of the GDP Price Deflator, which is presented below.

e) All other input assumptions should be the same as those previously utilized for your testimony and exhibits.

Year	EIA's GDP Price Deflator
1996	2.4%
1997	2.3%
1998	2.5%
1999	2.6%
2000	2.7%
2001	2.8%
2002	2.8%
2003	3.0%
2004	3.2%
2005	3.2%

2006	3.3%
2007	3.4%
2008	3.4%
2009	3.4%
2010	3.5%
2011	3.5%
2012	3.6%
2013	3.6%
2014	3.6%
2015	3.7%

A.1. Attachment 1 provides the results of a re-run of the EGEAS model (using the OCA's assumptions) in the "dynamic mode" to reflect the associated impacts on capacity additions and electricity prices resulting from the changes in assumptions identified by the OCA.

ATTACHMENT 1

PENNSYLVANIA POWER LIGHT COMPANY
Docket No. R-00973954

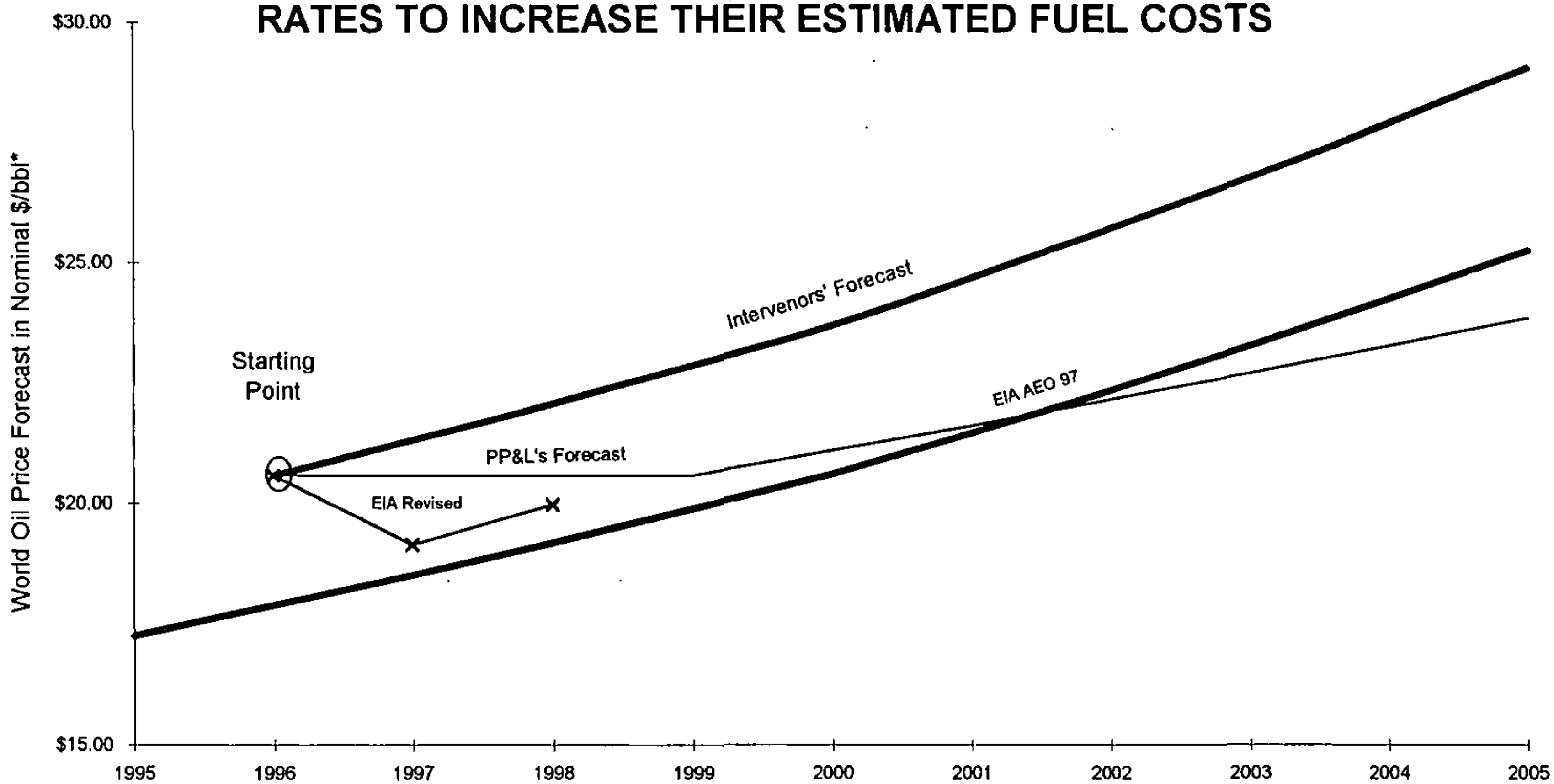
Office of Consumer Advocate
Set VIII

Based on future capacity addns. conforming to OCA assumptions

YEAR	$/Mwh
1999	22
2000	22
2001	23
2002	23
2003	24
2004	25
2005	25
2006	27
2007	28
2008	29
2009	30
2010	31
2011	32
2012	34
2013	35
2014	37
2015	39
2016	40

EXHIBIT STJ 12

THE "STARTING POINT" PROBLEM: INTERVENORS USE OLD FUEL ESCALATION RATES TO INCREASE THEIR ESTIMATED FUEL COSTS



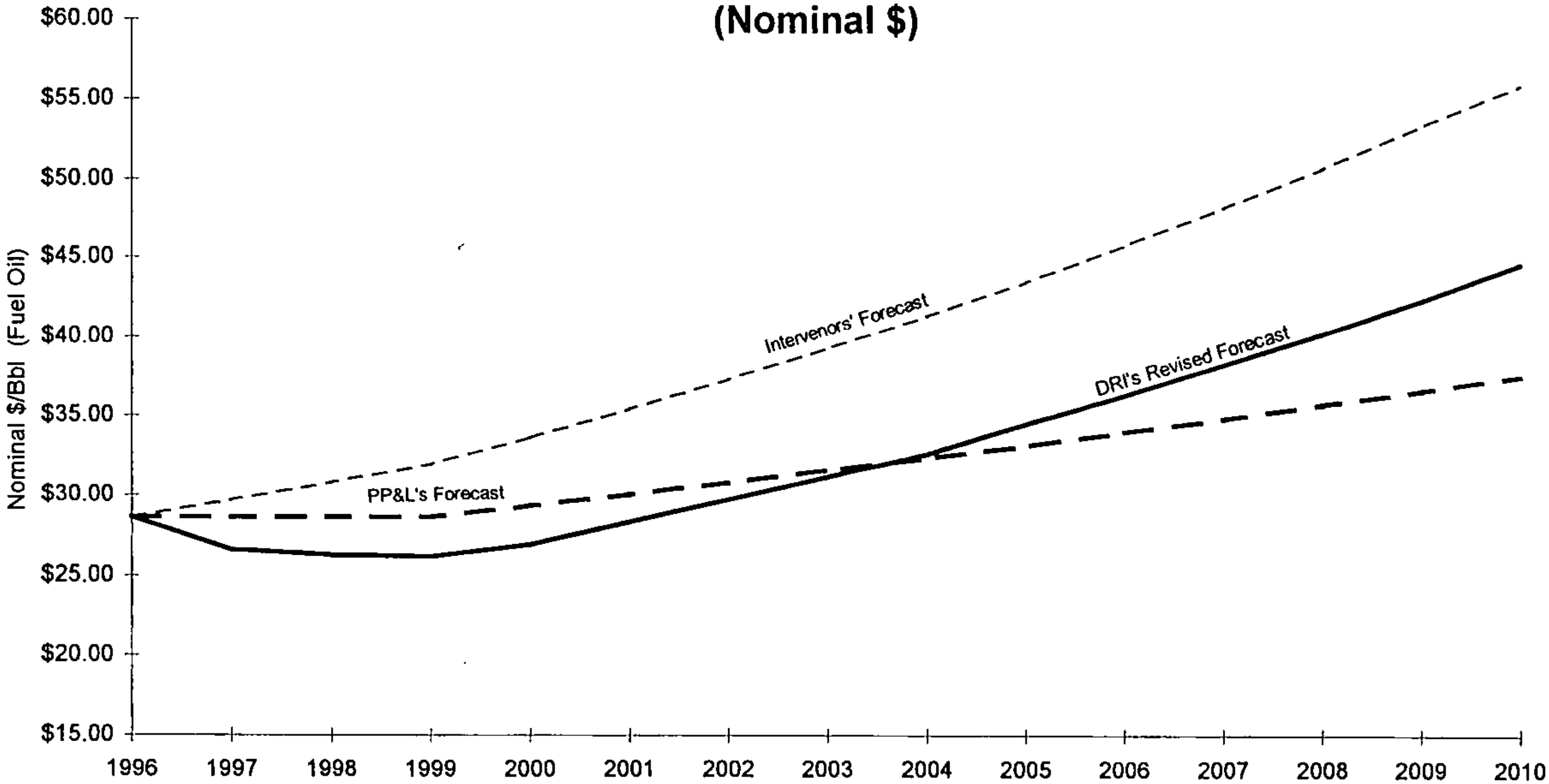
Sources: EIA, *Annual Energy Outlook*, 1997; EIA, *Monthly Energy Review*, April, 1997; EIA Short Term Energy Outlook, Third Quarter 1997. Direct Testimony of Robert Knecht, Table 3.

**Note: Annual Energy Outlook is based on data available through June, 1996.

Exhibit STJ-12

EXHIBIT STJ 13

DRI'S REVISED FUEL PRICE FORECAST IS CLOSER TO PP&L's FORECAST THAN INTERVENORS' FORECAST (Nominal $)

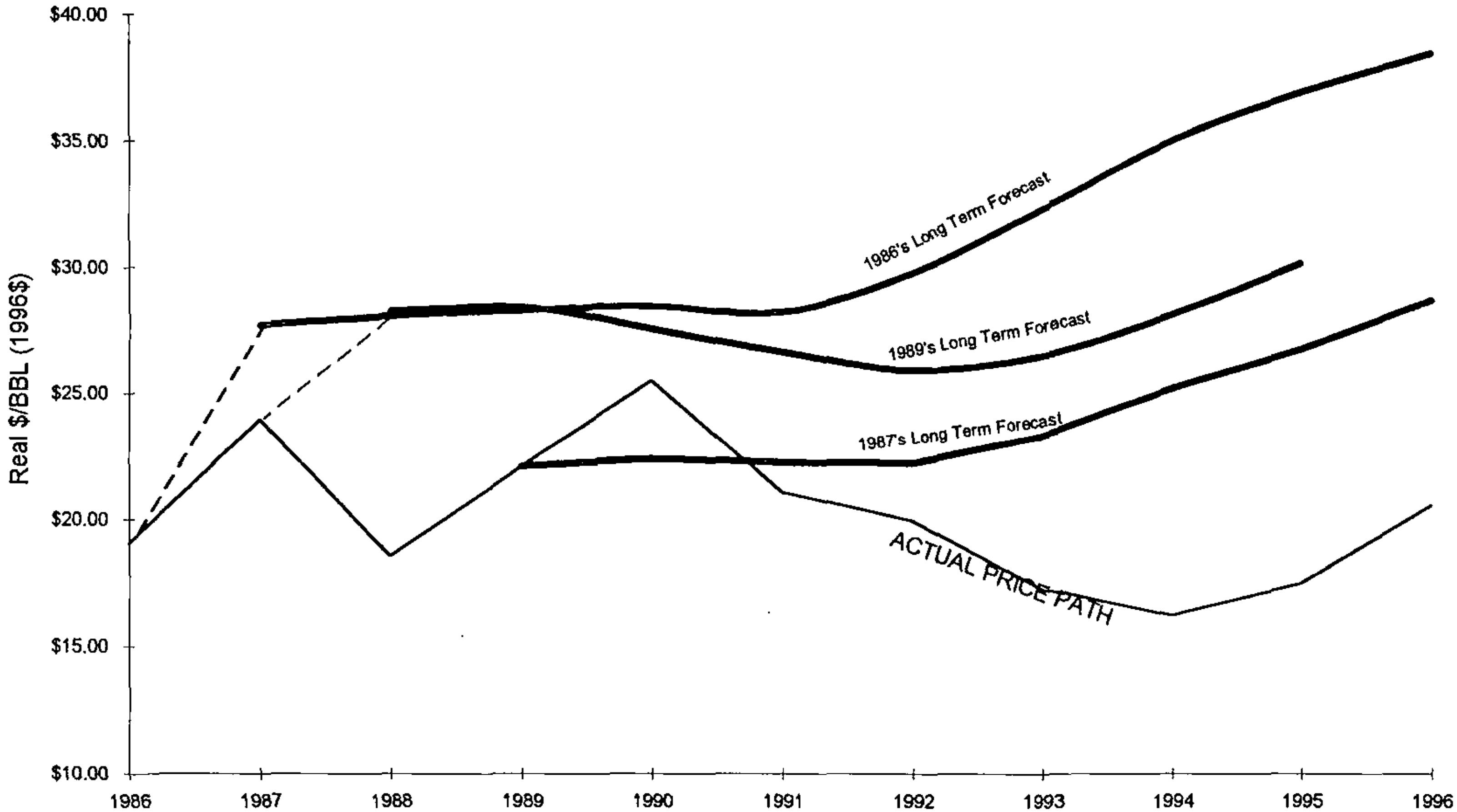


Sources: DRI/McGraw Hill, World Enegy Service *U.S. Outlook*, Spring 1997;
PPLICA Statement No. 2, Exhibit RJF-2.

Exhibit STJ-13

EXHIBIT STJ 14a

LONG-TERM FORECAST ACCURACY:
VARIOUS EIA FORECASTS FOR OIL PRICES

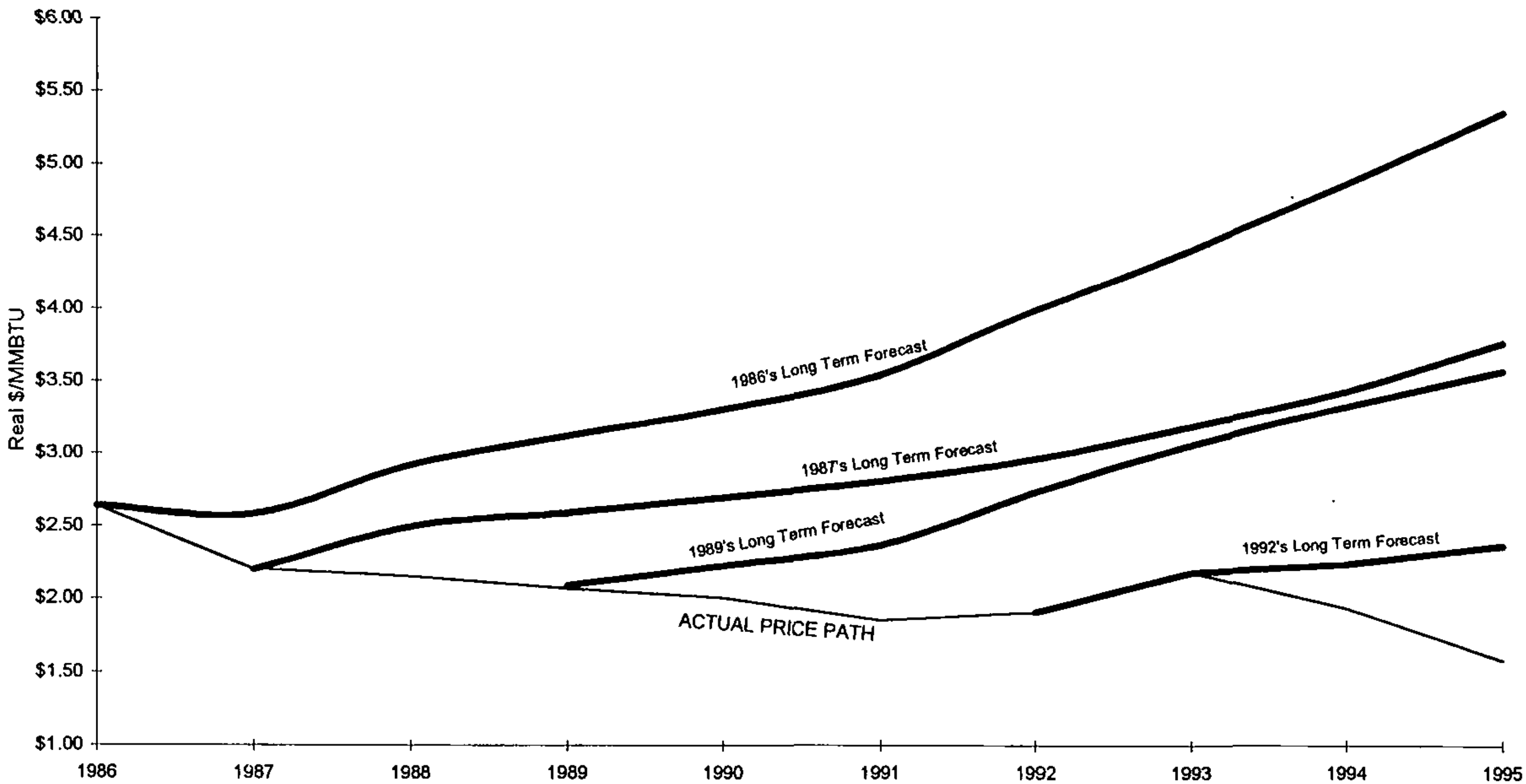


Source: EIA, *Issues in Midterm Analysis Forecasting,* 1997.

Exhibit STJ-14a

EXHIBIT STJ 14b

LONG-TERM FORECAST ACCURACY: VARIOUS EIA FORECASTS FOR NATURAL GAS PRICES



Source: EIA, *Issues in Midterm Analysis Forecasting*, 1997.

Exhibit STJ-14b

EXHIBIT STJ 15a

ENERGY PRICES BASED ON PP&L'S CONSTANT 2.5% INFLATION RATE: CORRECTING FOR THE USE OF "DOG-LEGGED" FORECASTS

Energy Prices ($/MWh) From PECO's Exh. JFB-14

	PECO			Intervenors			
	PHB	EDS	ICF	Smith	Falkenberg	PP&L	GPU
1999	20.2	21.5	22.2	22.4	23.9	22.0	20.9
2000	21.3	22.5	23.5	23.6	25.8	23.0	22.3
2001	22.3	24.1	24.5	25.1	26.0	24.0	23.4
2002	23.5	24.9	25.8	26.4	26.7	24.0	24.2
2003	24.7	25.8	26.5	28.1	27.1	25.0	25.4
2004	25.9	26.8	27.4	29.4	27.3	26.0	26.7
2005	27.1	27.6	28.5	31.8	28.3	26.0	27.9
2006	28.3	26.4	29.8	34.1	29.5	27.0	28.5
2007	29.5	29.8	31.0	36.0	30.9	29.0	29.2
2008	30.8	31.1	32.4	38.3	31.9	30.0	29.6
2009	32.1	32.0	33.7	39.6	33.3	31.0	30.1
2010	33.8	33.7	35.3	42.3	34.5	32.0	30.9
2011	35.5	35.0	38.4	44.1	36.0	32.0	32.0
2012	37.3	36.5	40.0	46.1	37.6	33.0	32.9
2013	39.3	37.8	41.9	48.0	38.8	35.0	35.3
2014	41.3	39.7	44.3	50.3	40.2	35.0	36.6
2015	43.4	42.0	46.2	52.8	41.6	36.0	38.0

Energy Prices ($/MWh) Using PP&L's 2.5% Inflation Rate

	PECO			Intervenors			
	PHB	EDS	ICF	Smith	Falkenberg	PP&L	GPU
1999	20.5	21.8	22.5	22.7	24.0	22.0	20.9
2000	21.6	22.8	23.8	23.9	25.8	23.0	22.3
2001	22.5	24.4	24.8	25.4	25.9	24.0	23.4
2002	23.7	25.1	26.0	26.6	26.5	24.0	24.2
2003	24.8	25.9	26.6	28.2	26.8	25.0	25.4
2004	25.9	26.8	27.4	29.4	26.8	26.0	26.7
2005	26.9	27.4	28.3	31.5	27.6	26.0	27.9
2006	27.8	26.0	29.3	33.5	28.6	27.0	28.5
2007	28.7	29.0	30.2	35.1	29.7	29.0	29.2
2008	29.7	30.0	31.2	36.9	30.4	30.0	29.6
2009	30.6	30.5	32.2	37.8	31.4	31.0	30.1
2010	31.9	31.8	33.3	40.0	32.3	32.0	30.9
2011	33.2	32.7	35.9	41.2	33.3	32.0	32.0
2012	34.5	33.8	37.0	42.7	34.5	33.0	32.9
2013	36.0	34.6	38.4	44.0	35.2	35.0	35.3
2014	37.4	36.0	40.2	45.6	36.1	35.0	36.6
2015	38.9	37.7	41.5	47.4	36.9	36.0	38.0

Note: Prices of PHB, EDS, ICF, and Smith deflated at DRI's Spring 1997 GDP Price Deflator; Falkenberg at EIA's GDP Price Deflator from Annual Energy Outlook 1997

EXHIBIT STJ 15b

Exhibit STJ-15b

CAPACITY PRICES BASED ON PP&L'S CONSTANT 2.5% INFLATION RATE: CORRECTING FOR THE USE OF "DOG-LEGGED" FORECASTS

Capacity Prices ($/kW-year) From PECO's Exh. JFB-14

	PECO			Intervenors			
	PHB	EDS	ICF	Smith	Falkenberg	PP&L	GPU
1999	16.0	23.9	23.9	19.7	24.2	22.0	23.1
2000	27.0	31.1	31.1	30.4	30.8	29.0	35.5
2001	45.4	45.1	45.1	41.7	46.5	38.0	38.6
2002	46.7	49.1	46.7	43.1	49.0	50.0	41.9
2003	48.1	50.3	47.8	44.2	53.4	49.0	42.9
2004	49.6	52.7	49.4	45.7	58.2	48.0	44.0
2005	51.3	54.2	51.0	47.1	60.0	44.0	45.1
2006	53.1	57.3	52.9	48.9	61.2	45.0	46.2
2007	55.0	58.0	54.5	50.4	61.3	50.0	47.4
2008	56.9	58.7	56.5	52.2	64.4	51.0	48.5
2009	59.0	61.7	58.4	54.0	64.6	53.0	49.8
2010	61.0	64.1	60.8	56.2	67.4	54.0	51.0
2011	63.2	64.9	62.7	58.0	68.5	55.0	52.3
2012	65.5	65.8	65.1	60.1	69.7	56.0	53.6
2013	67.8	69.4	67.5	62.3	73.6	57.0	54.9
2014	70.2	71.3	69.8	64.5	77.3	59.0	56.3
2015	72.8	70.3	72.2	66.7	80.0	60.0	57.7

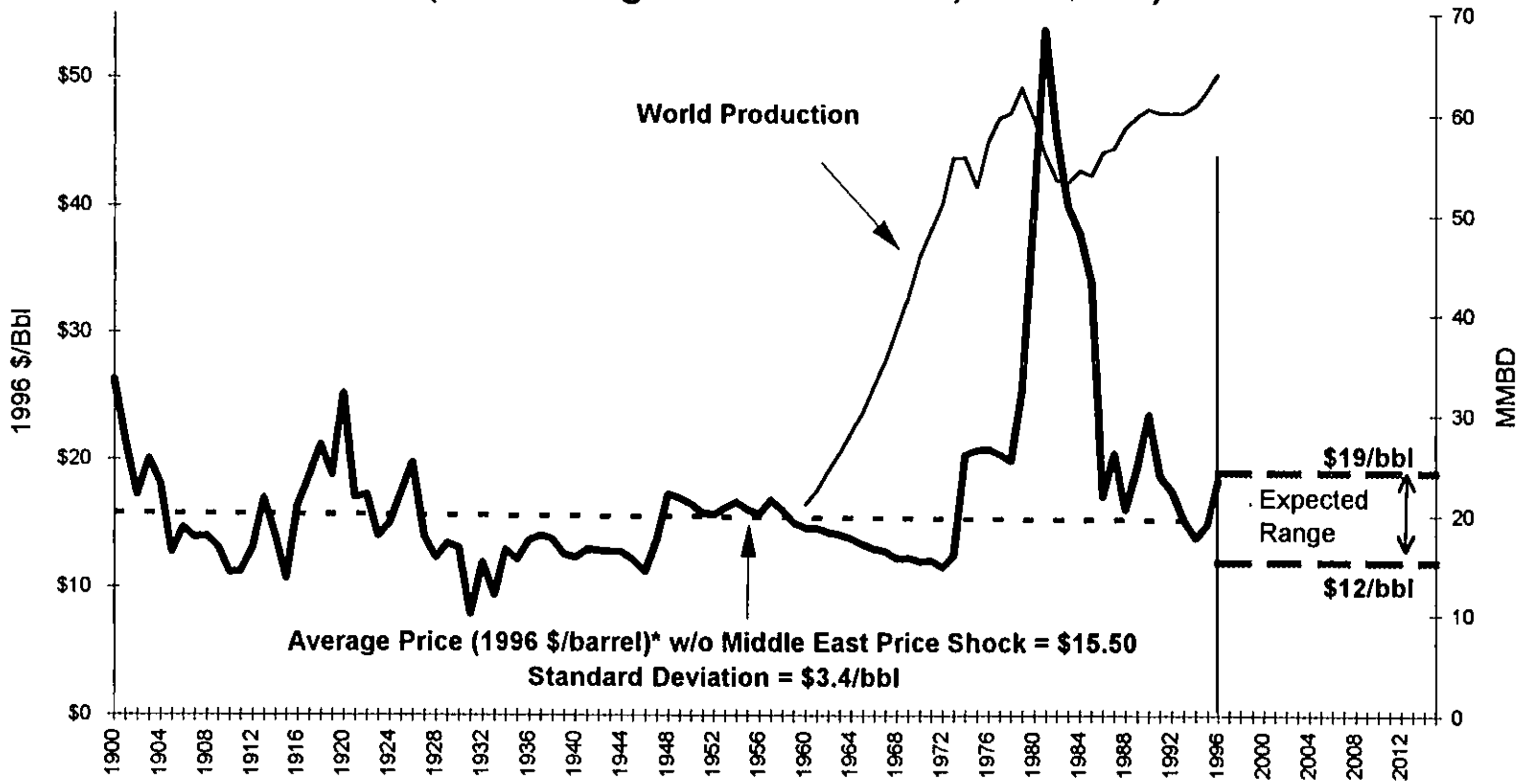
Capacity Prices ($/kW-year) Using PP&L's 2.5% Inflation Rate

	PECO			Intervenors			
	PHB	EDS	ICF	Smith	Falkenberg	PP&L	GPU
1999	16.2	24.2	24.2	20.0	24.3	22.0	23.1
2000	27.3	31.5	31.5	30.8	30.8	29.0	35.5
2001	45.9	45.6	45.6	42.2	46.4	38.0	38.6
2002	47.0	49.5	47.0	43.4	48.7	50.0	41.9
2003	48.3	50.5	48.0	44.4	52.8	49.0	42.9
2004	49.5	52.6	49.3	45.6	57.2	48.0	44.0
2005	50.9	53.8	50.6	46.7	58.6	44.0	45.1
2006	52.2	56.3	52.0	48.1	59.3	45.0	46.2
2007	53.6	56.5	53.1	49.1	58.9	50.0	47.4
2008	54.9	56.6	54.5	50.3	61.3	51.0	48.5
2009	56.3	58.9	55.7	51.5	61.0	53.0	49.8
2010	57.6	60.6	57.4	53.1	63.0	54.0	51.0
2011	59.1	60.7	58.6	54.2	63.4	55.0	52.3
2012	60.6	60.9	60.2	55.6	63.9	56.0	53.6
2013	62.1	63.6	61.8	57.1	66.8	57.0	54.9
2014	63.7	64.7	63.3	58.5	69.4	59.0	56.3
2015	65.3	63.1	64.8	59.8	71.0	60.0	57.7

Note: Prices of PHB, EDS, ICF, and Smith deflated at DRI's Spring 1997 GDP Price Deflator; Falkenberg at EIA's GDP Price Deflator from Annual Energy Outlook 1997

EXHIBIT STJ 16

THIS CENTURY'S OIL PRICES
(U.S. Average Wellhead Prices, 1996 $/Bbl)



*The period corresponding to the impact of the Iranian Revolution, 1979-85, is not part of the average price.

Sources: DRI/McGraw Hill; Oil and Gas Journal, Energy Database; EIA *Annual Energy Review*, 1996.

Exhibit STJ-16

EXHIBIT STJ 16a

PPL RECOGNIZES REAL FUEL PRICES ARE HIGHLY CORRELATED. INTERVENORS' FORECASTS IGNORE HISTORY AND PRODUCE LOW OR NEGATIVE CORRELATIONS.

I. Real Fuel Price Correlations (1981-1995)

	OIL	GAS	COAL	URANIUM
OIL	N/A	.84	.90	.88
GAS	.84	N/A	.92	.85
COAL	.90	.92	N/A	.91
URANIUM	.88	.85	.91	N/A

II. PPL Forecast (1996-2015)

	OIL	GAS	COAL	URANIUM
OIL	N/A	1.00	.62	.81
GAS	1.00	N/A	.62	.81
COAL	.62	.62	N/A	.89
URANIUM	.81	.81	.89	N/A

III. DRI (OCA) Forecast (1996-2015)

	OIL	GAS	COAL	URANIUM
OIL	N/A	.99	-.998	-.82
GAS	.99	N/A	-.996	-.87
COAL	-.998	-.996	N/A	.84
URANIUM	-.82	-.87	.84	N/A

IV. EIA (PPLICA) Forecast (1996-2015)

	OIL	GAS	COAL	URANIUM
OIL	N/A	.97	.36	.18
GAS	.97	N/A	.46	.38
COAL	.36	.46	N/A	.82
URANIUM	.18	.38	.82	N/A

Sources:
EIA, *Annual Energy Review 1996* Table 3.1; DRI/McGraw Hill ;
PPLICA Statement No. 2, Exhibit RJF-2.

EXHIBIT STJ 17

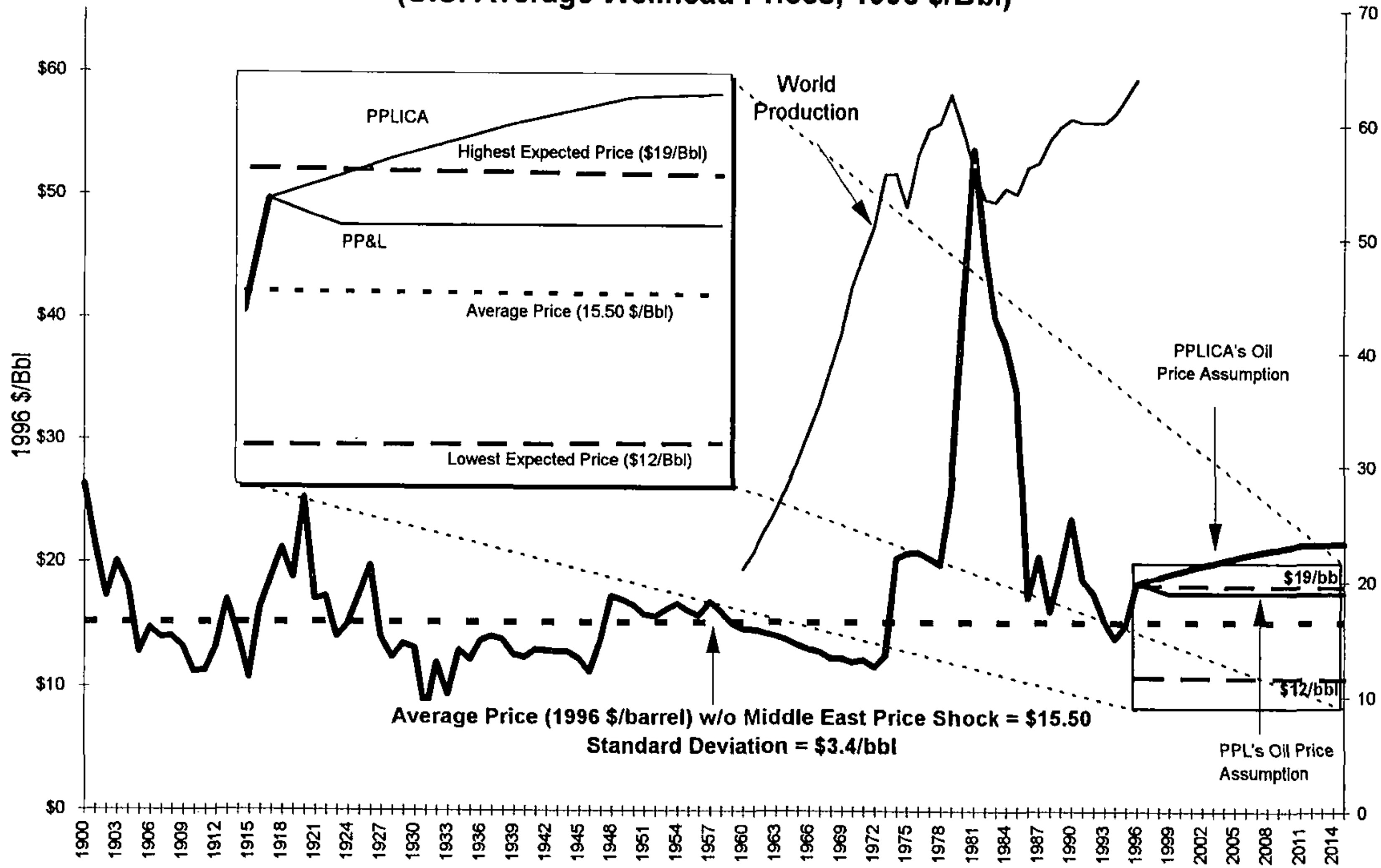
A TEN YEAR LOOK AT NATURAL GAS RESERVES, CONSUMPTION AND PRICES

1987 Total Proved Natural Gas Reserves Tcf	Total US Natural Gas Consumption 1986-1995 Tcf	1996 Total Proved Natural Gas Reserves Tcf
196	-196	216
1987 Average Wellhead Price (1996$)		**1996 Average Wellhead Price (1996$)**
$2.66		$2.24

Sources: Reserves - Table 4.2 "Crude Oil and Natural Gas Field Counts, Cumulative Production, Proved Reserves and Ultimate Recovery, End of Year 1977-1995" Consumption - Table 6.1 "Natural Gas Overview, 1949-1996" (EIA Annual Energy Review 1996);Potential Gas Committee Report cited in the Energy Daily, April 4, 1997.
Prices - Table 6.8: "Natural Gas Wellhead and Import Prices, 1949-1995" (DOE/EIA)

EXHIBIT STJ 18

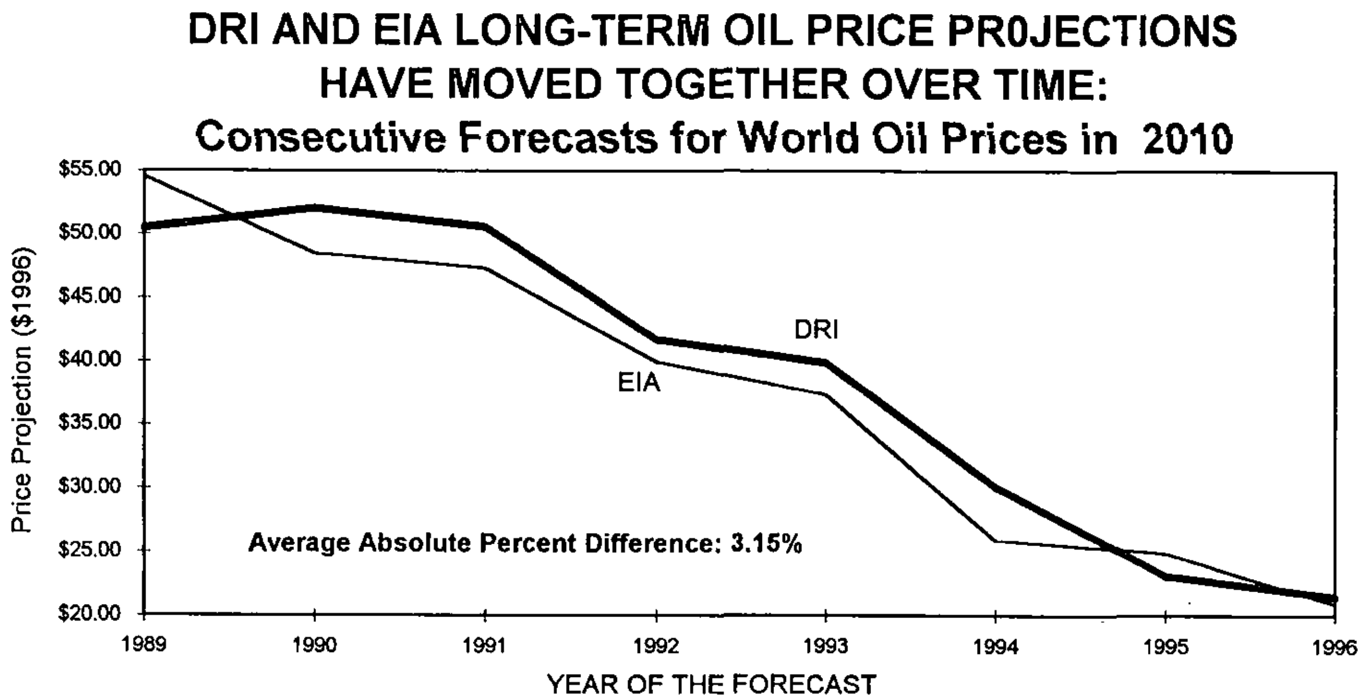
THIS CENTURY'S OIL PRICES
(U.S. Average Wellhead Prices, 1996 $/Bbl)



*The period corresponding to the impact of the Iranian Revolution, 1979-85, is not part of the average price.
Sources: DRI/McGraw Hill; Oil and Gas Journal, Energy Database; EIA Annual Energy Review, 1996.

Exhibit STJ-18

EXHIBIT STJ 19



Source: EIA, 1997 (Data Provided by Susan Holte, EIA Forecasting Group).

Exhibit STJ-19

EXHIBIT STJ 20

FACTORS AFFECTING FUTURE NATURAL GAS CONSUMPTION FOR ELECTRIC GENERATION IN A COMPETITIVE ENVIRONMENT

Premise:

Any forecast overstates natural gas demand for electric generation.

- Forecasters assume that most new capacity will be built by non-utility generators (NUGs)
- Forecasters fail to account for the impact of competition and technology on heat rates.
- Forecasters tend to ignore displacement. They estimate that gas demand is the sum of demand by NUGs plus existing utility generation capacity.
- NUGs do not increase gas consumption. Increased sales of electricity increase gas consumption.
- Initial peak growth determines capacity additions.
  - Growth in peak demand usually higher than the growth in sales.
  - Adding peak demand capacity improves system heat rate by displacing less efficient capacity.
- Forecasters can forget that opening the electric market to retail and wholesale competition will increase power flows across regions (i.e., imports and exports).
  - Imports and exports will increase the utilization of lowest cost capacity that can economically serve load.
- In some regions, existing coal-fired units with lower marginal costs will be more fully utilized and operating lives will be extended at the expense of additional gas use.

Source: *The Energy Daily*, April 11, 1997.

EXHIBIT STJ 21

DRI AND EIA INFLATION FORECASTS ARE BASICALLY THE SAME

YEARS	EIA - '97	DRI-Fall '96
1997-00	2.5%	2.3%
2000-05	3.0%	3.0%
2005-10	3.4%	3.6%
2010-15	3.6%	3.5%

Source: PPLICA Statement No. 2, Exhibit RJF-2.

EXHIBIT STJ 22

THE HEAT RATE DEBATE:
THE PROPER TREATMENT OF INCREMENTAL V. AVERAGE COST

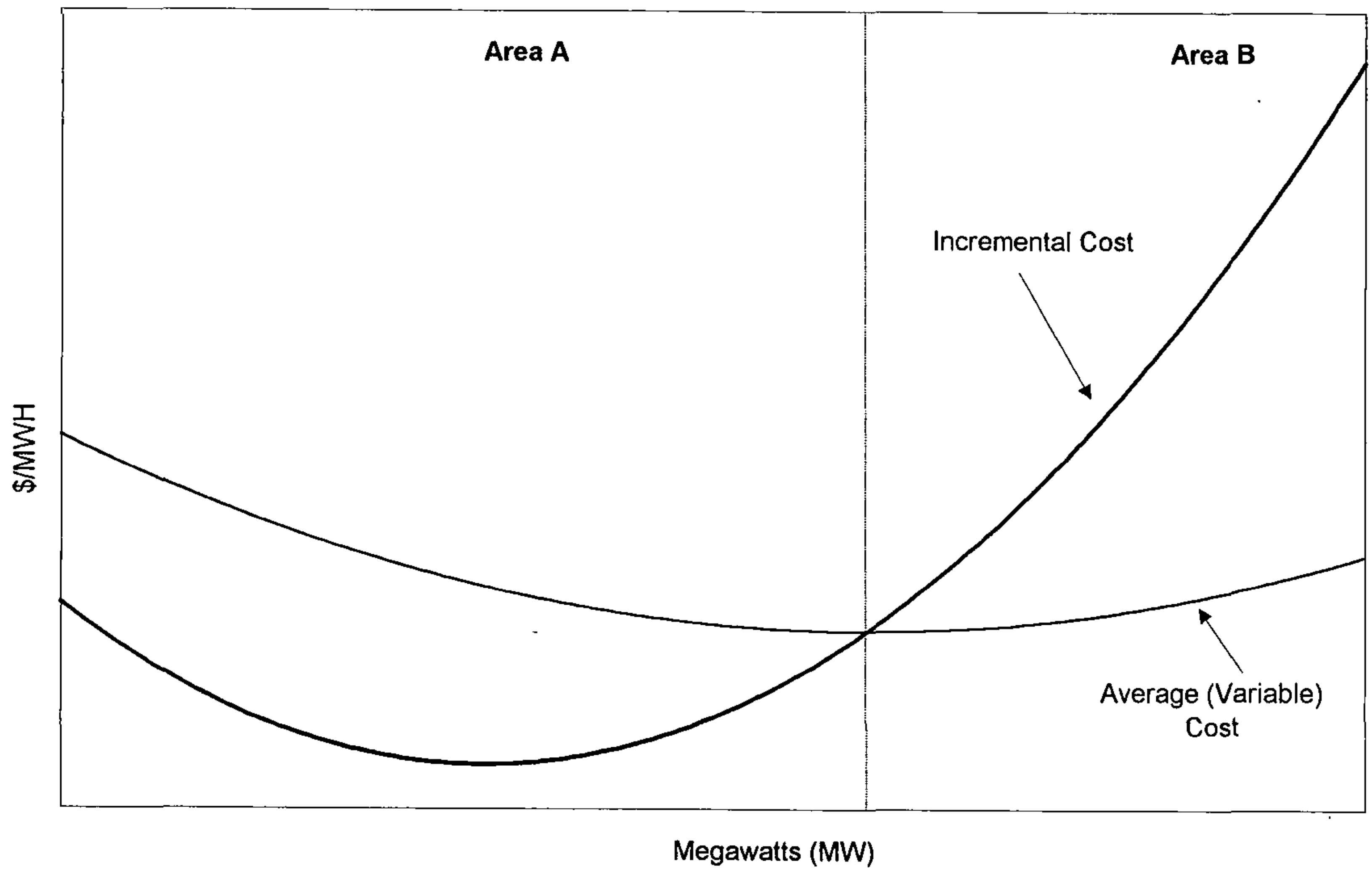


Exhibit STJ-22

EXHIBIT STJ 23

GENERATOR'S BID CURVE
vs.
INTERVENORS' HEAT RATE "CURVE"

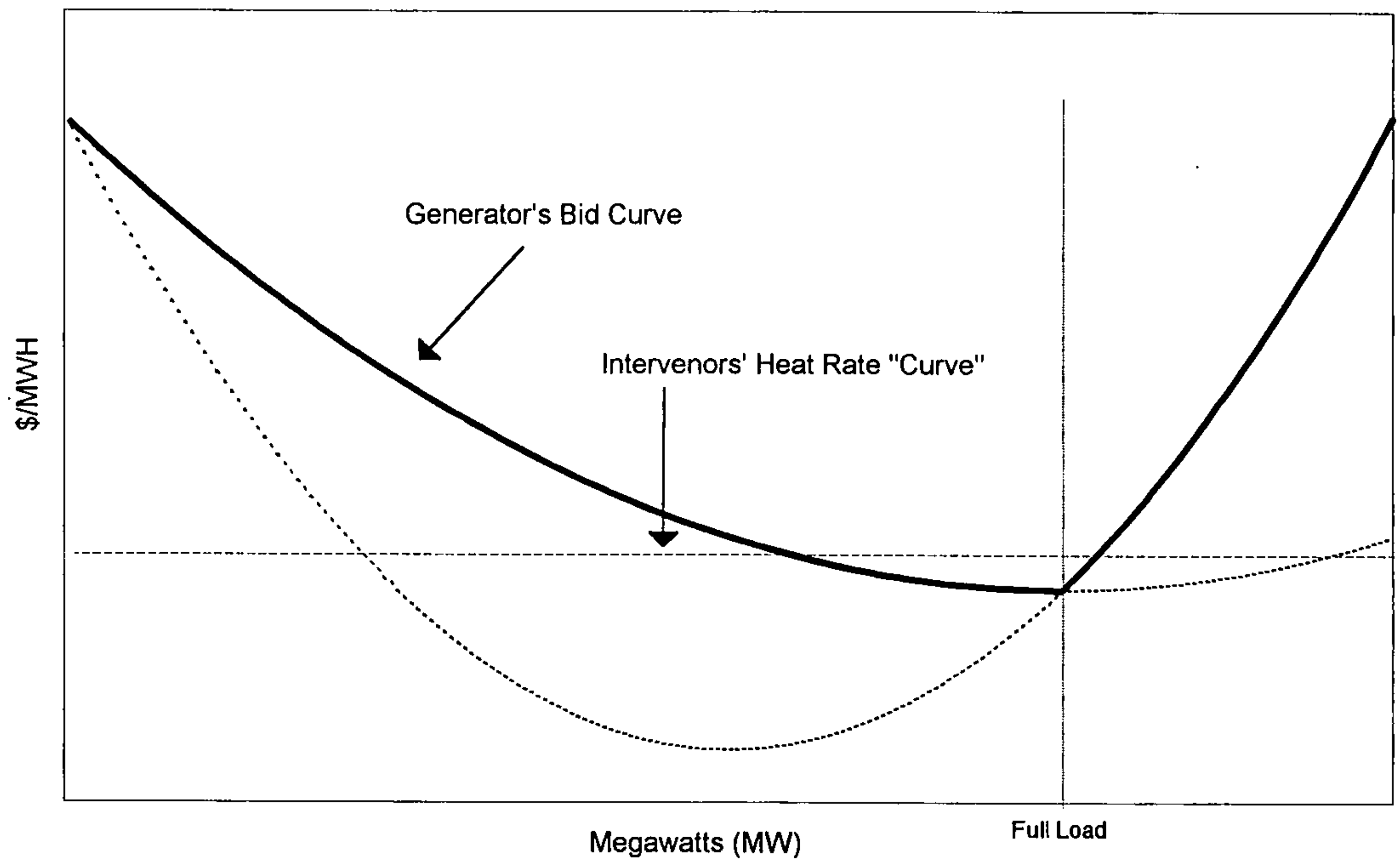


Exhibit STJ-23

EXHIBIT STJ 24

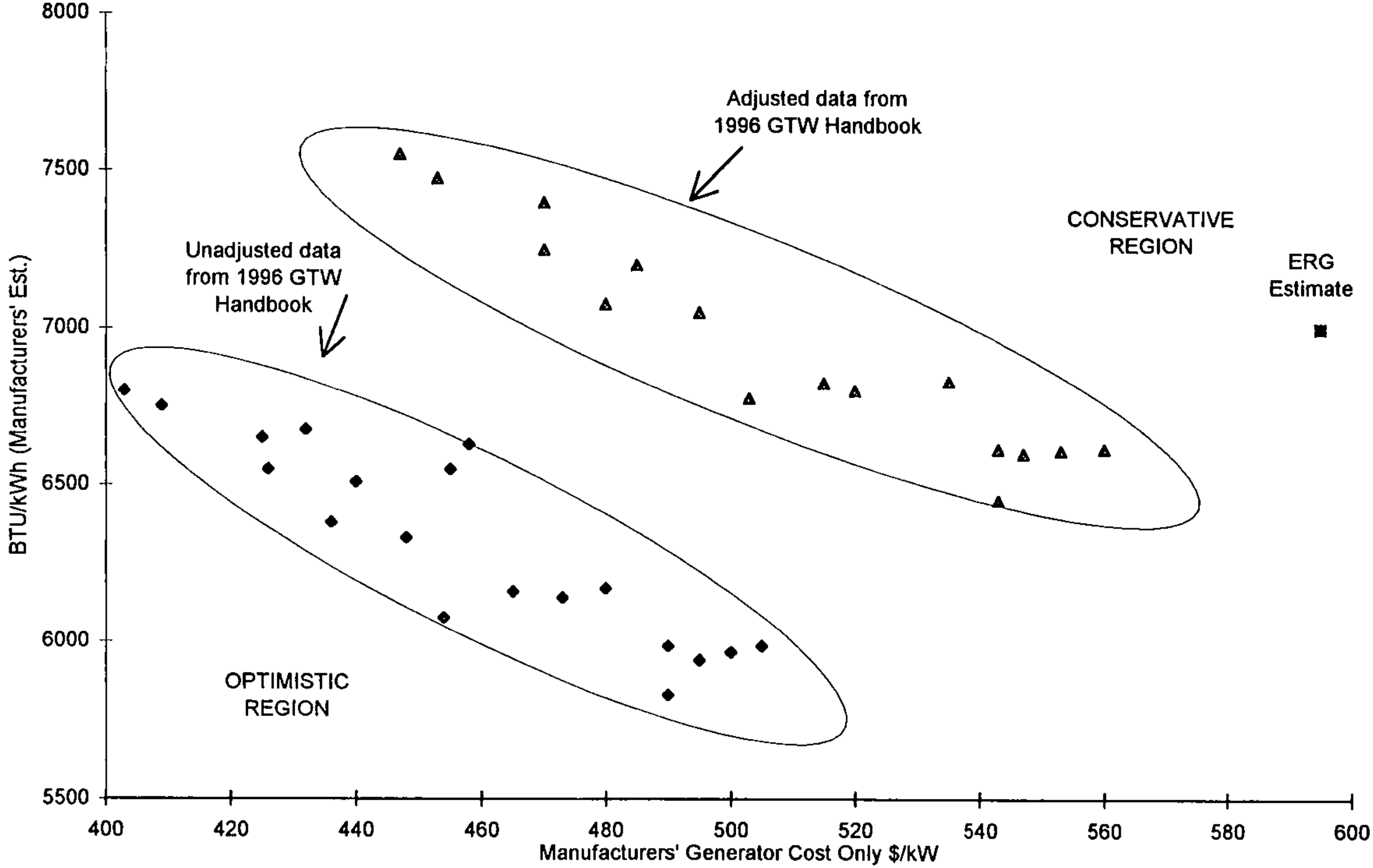
PP&L'S ENERGY FORECAST
vs.
FALKENBERG'S HEAT RATE APPROACH:
The Bottom Line Impact on Energy Prices

	PP&L's Energy Forecast ($/MWh)	Falkenberg's Heat Rate Approach ($/MWh)	Difference ($/MWh)
1997	22.26	22.32	0.06
1998	21.38	20.53	-0.85
1999	21.78	21.41	-0.38
2000	22.56	21.91	-0.65
2001	23.77	23.62	-0.15
2002	23.92	23.96	0.03
2003	24.77	24.86	0.09
2004	25.77	25.51	-0.26
2005	26.42	26.47	0.05
2006	27.20	27.07	-0.13
2007	28.73	28.78	0.05
2008	29.75	29.77	0.02
2009	30.56	30.70	0.14
2010	31.57	31.71	0.13
2011	32.47	32.60	0.13
2012	33.42	33.50	0.08
2013	34.59	34.53	-0.05
2014	34.91	34.92	0.00
2015	35.93	35.90	-0.04
2016	36.76	36.65	-0.11
Average	**28.43**	**28.34**	**-0.09**

Source: PP&L/EGEAS model

EXHIBIT STJ 25

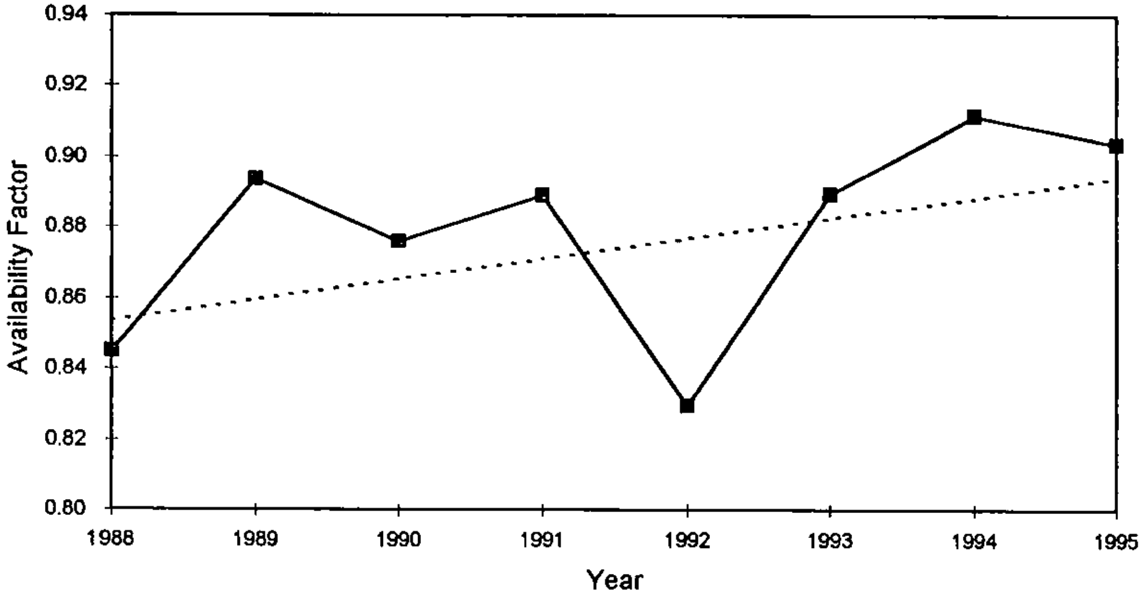
PP&L's COMBINED CYCLE ASSUMPTIONS ARE CONSERVATIVE COMPARED TO INTERVENORS' EVEN AFTER ADJUSTMENT



Sources: PPLICA Statement No. 2, Exhibit RJF-6 (Estimated); *Gas Turbine World 1996* Handbook.

Exhibit STJ-25

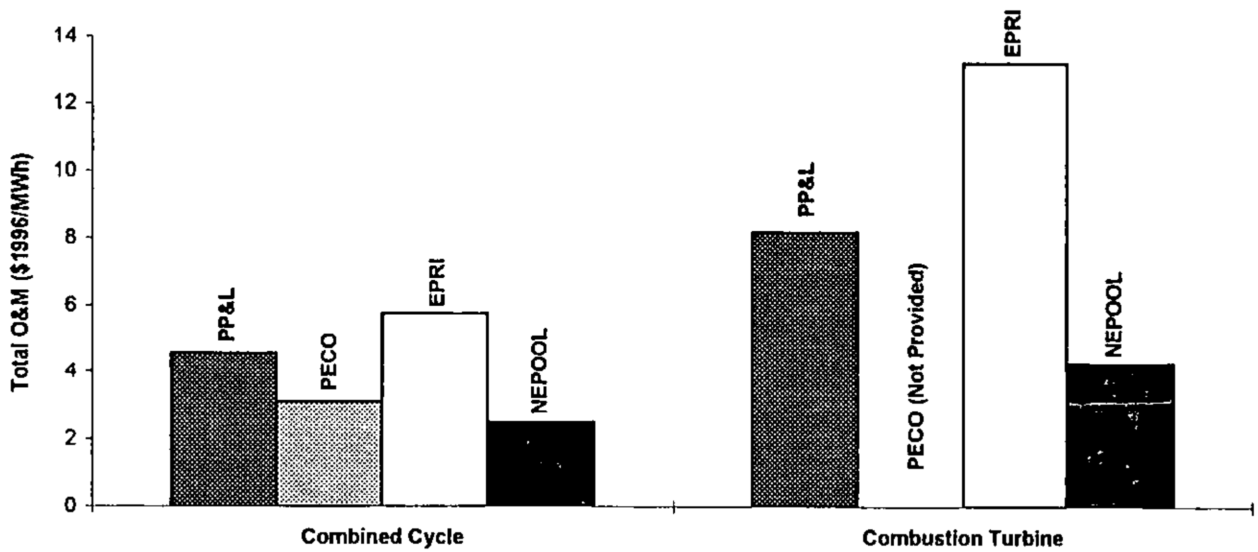
EXHIBIT STJ 26



Source: North American Electric Reliability Council (NERC), Generating Availability Data System (1996).

Exhibit STJ-26

EXHIBIT STJ 27



Note: Total O&M calculated assuming 0.70 CF for CC and 0.10 CF for CT
All figures converted to 1996 Dollars

Sources: PECO - Docket No. R-00973953; EPRI Technical Assessment Guide (1993);
NEPOOL - Generation Task Force Long-Range Study Assumptions (1994)

Exhibit STJ-27

EXHIBIT STJ 28

PRESENT VALUE OF CAPACITY ADDITIONS USING VENDOR DATA

Vendor Identification	Capacity (MW)	Heat Rate (BTU/kWhr)	Capital Cost ($/kW)	NPV #1 ($mm)	NPV #2 ($mm)
KA13E2-1	244.2	6330	515	16	20
KA24-1	248.3	5940	569	15	19
GUD 1S84.3A	250	5985	580	12	16
S-107FA	253.5	6160	535	17	20
1x1 501F	256.4	6075	522	22	25
S-207EA	262.2	6750	470	16	20
GUD 1S.94.3A	354	5965	575	19	24
S-109FA	345.7	6170	552	18	23
KA26-1	366	5830	564	27	32
KA11N2-3	512	6650	489	29	36

Source: 1996 *Gas Turbine World Handbook* (Capital costs inflated 15% to account for soft costs.)

Notes:
1) Results obtained using Knecht's spreadsheet modified to rectify escalation errors, capacity prices and O & M costs.
2) NPV #2 is Knecht version RDK2 schedule 5 and NPV#1 is Knecht version RDK2 schedule 6 With schedule 6 maintenance capital and gas transmission charges are not assessed.
3) Dr. Jones' assumptions (410MW, 7000Btu/Kwh, and $595/KW) produce slightly negative present values (NPV#2) using Mr. Knecht's assumptions.

EXHIBIT STJ 28a

PROJECT ECONOMICS FOR CURRENTLY AVAILABLE COMBINED CYCLE UNITS: COLUMN "NPV #1"

Test for Price Sufficiency to Support New Combined Cycle Unit: ABB GT11N2

Inflation	2.50%	Fixed O&M ($/KW/yr)	$9.00	Maintenance Capital	0.00% of book value
Capacity (MW)	512	Variable O&M ($/MWh)	$3.10	Working Capital	5.00% of revenues
Capital Cost ($/KW)	$489.00	Capacity Factor		Income Tax rate	41.50%
Fuel Cost (96$/MMBTU)	$2.30	Debt Cost	8.00%	Decommissioning	10.00% of investment cost
Gas Transmission ($/MMBTU)	$0.00	Debt Share	38.60%		
Heat Rate (BTU/KW-h)	6,650				

Inflation factor										
Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Capacity Factor						55.04%	55.97%	61.13%	67.11%	71.12%
Capacity Price ($/KW/yr)	29.0	38.0	50.0	49.0	48.0	44.0	45.0	50.0	51.0	53.0
Energy Price ($/MWh)	23.0	24.0	24.0	25.0	26.0	26.0	27.0	29.0	30.0	31.0
Generation (GWh)	0	0	0	0	0	2,469	2,510	2,742	3,010	3,190
Capacity Revenues ($mm)	14.848	19.456	25.6	25.088	24.576	22.528	23.04	25.6	26.112	27.136
Energy Revenues ($mm)	0.00	0.00	0.00	0.00	0.00	64.18	67.78	79.51	90.30	98.88
Revenues	0.00	0.00	0.00	0.00	0.00	86.71	90.82	105.11	116.41	126.02
Fuel Costs ($/MWh)	15.30	15.68	16.07	16.47	16.88	17.30	17.74	18.18	18.64	19.10
Gas Transmission Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Variable O&M Costs ($/MWh)	3.29	3.34	3.39	3.44	3.49	3.54	3.60	3.69	3.78	3.87
Fixed O&M Costs ($/KW/yr)	9.69	9.93	10.18	10.44	10.70	10.97	11.24	11.52	11.81	12.10
Fuel Costs ($mm)	0.00	0.00	0.00	0.00	0.00	42.72	44.53	49.85	56.09	60.93
Variable O&M Costs ($mm)	0.00	0.00	0.00	0.00	0.00	8.75	9.03	10.11	11.38	12.36
Fixed O&M Costs ($mm)	0.00	0.00	0.00	0.00	0.00	5.61	5.75	5.90	6.05	6.20
Decommissioning										
Total Operating Costs ($mm)	0.00	0.00	0.00	0.00	0.00	57.08	59.31	65.86	73.51	79.48
Depreciation ($mm)	(one and one-half declining balance method					22.32	20.65	19.10	17.67	16.34
Interest ($mm)	with switch to SL using half year convention)					9.19	8.50	7.86	7.27	6.73
Income Taxes ($mm)						-0.78	0.98	5.10	7.45	9.74
Year Index for Depreciation						20	19.5	18.5	17.5	16.5
Net Income						-1.10	1.38	7.19	10.51	13.73
Capital Expenditures ($mm)					($297.61)					
EOY Book Value					297.61	275.29	254.64	235.54	217.88	201.54
EOY Debt					114.88	106.26	98.29	90.92	84.10	77.79
Working Capital						4.34	4.54	5.26	5.82	6.30
Cash Flow										
Net Income						-1.10	1.38	7.19	10.51	13.73
Depreciation						22.32	20.65	19.10	17.67	16.34
Capital Expenditures					($297.61)					
Debt Cash Flow					114.88	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)
Working Capital						(4.34)	(0.21)	(0.71)	(0.57)	(0.48)
Net Cash Flow					($182.73)	13.06	17.99	21.75	23.76	25.76

Year	2010	2011	2012	2013	2014	2015	2020	2025	2030	2034
Capacity Factor	72.60%	75.39%	76.82%	79.37%	79.35%	81.76%	83.00%	83.00%	83.00%	83.00%
Capacity Price ($/KW/yr)	54.0	55.0	56.0	57.0	59.0	60.0	67.9	76.8	86.9	95.9
Energy Price ($/MWh)	32.0	32.0	33.0	35.0	35.0	36.0	40.7	46.1	52.1	57.6
Generation (GWh)	3,256	3,381	3,445	3,560	3,559	3,667	3,723	3,723	3,723	3,723
Capacity Revenues ($mm)	27.648	28.16	28.672	29.184	30.208	30.72	34.76	39.32	44.49	49.11
Energy Revenues ($mm)	104.20	108.20	113.70	124.59	124.56	132.01	151.63	171.55	194.09	214.24
Revenues	131.85	136.36	142.37	153.78	154.77	162.73	186.38	210.88	238.59	263.35
Fuel Costs ($/MWh)	19.58	20.07	20.57	21.08	21.61	22.15	25.06	28.36	32.08	35.41
Gas Transmission Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Variable O&M Costs ($/MWh)	3.97	4.07	4.17	4.28	4.38	4.49	5.08	5.75	6.51	7.18
Fixed O&M Costs ($/KW/yr)	12.41	12.72	13.03	13.36	13.69	14.04	15.88	17.97	20.33	22.44
Fuel Costs ($mm)	63.75	67.88	70.87	75.06	76.91	81.23	93.30	105.56	119.43	131.83
Variable O&M Costs ($mm)	12.93	13.76	14.37	15.22	15.60	16.47	18.92	21.41	24.22	26.73
Fixed O&M Costs ($mm)	6.35	6.51	6.67	6.84	7.01	7.19	8.13	9.20	10.41	11.49
Decommissioning										38.78
Total Operating Costs ($mm)	83.03	88.13	91.92	97.12	99.52	104.89	120.35	136.17	154.06	208.83
Depreciation ($mm)	15.12	13.98	12.93	12.76	12.76	12.76	12.76	6.38	0.00	0.00
Interest ($mm)	6.22	5.76	5.32	4.93	4.53	4.14	2.17	0.20	0.00	0.00
Income Taxes ($mm)	11.40	11.83	13.36	16.17	15.75	16.99	21.21	28.27	35.08	22.63
Year Index for Depreciation	15 5	14.5	13.5	12.5	11.5	10.5	5.5	0.5		
Net Income	16.07	16.67	18.83	22.80	22.20	23.95	29.90	39.86	49.45	31.90
Capital Expenditures ($mm)										
EOY Book Value	186.42	172.44	159.51	146.75	133.99	121.23	57.42	0.00	0.00	0.00
EOY Debt	71.98	66.56	61.57	56.64	51.72	46.79	22.17	0.00	0.00	0.00
Working Capital	6.59	6.82	7.12	7.69	7.74	8.14	9.32	10.54	11.93	13.17
Cash Flow										
Net Income	16.07	16.67	18.83	22.80	22.20	23.95	29.90	39.86	49.45	31.90
Depreciation	15.12	13.98	12.93	12.76	12.76	12.76	12.76	6.38	0.00	0.00
Capital Expenditures										
Debt Cash Flow	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)
Working Capital	(0.29)	(0.23)	(0.30)	(0.57)	(0.05)	(0.40)	(0.23)	(0.26)	(0.29)	(0.32)
Net Cash Flow	27.07	26.60	27.64	31.16	31.09	32.49	38.60	42.15	45.33	27.75

Internal rate of return	14.22%
NPV @ 12.5% at first	$29.05

Note: Some columns are hidden for reporting purposes

EXHIBIT STJ 28b

PROJECT ECONOMICS FOR CURRENTLY AVAILABLE COMBINED CYCLE UNITS: COLUMN "NPV #2"

Test for Price Sufficiency to Support New Combined Cycle Unit: ABB GT11N2

Inflation	2.50%	Fixed O&M ($/KW/yr)	$9.00	Maintenance Capital	0.00%
Capacity (MW)	512	Variable O&M ($/MWh)	$3.10	Working Capital	0.00%
Capital Cost ($/KW)	$489.00	Capacity Factor		Income Tax rate	41.50%
Fuel Cost (96$/MMBTU)	$2.30	Debt Cost	8.00%	Decommissioning	0.00%
Gas Transmission ($/MMBTU)	$0.00	Debt Share	38.60%		
Heat Rate (BTU/KW-h)	6,650				

Inflation factor																				
Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030	2034
Capacity Factor						55.04%	55.97%	61.13%	67.11%	71.12%	72.60%	75.39%	76.82%	79.37%	79.35%	81.76%	83.00%	83.00%	83.00%	83.00%
Capacity Price ($/KW/yr)	29.0	38.0	50.0	49.0	48.0	44.0	45.0	50.0	51.0	53.0	54.0	55.0	56.0	57.0	59.0	60.0	67.9	76.8	86.9	95.9
Energy Price ($/MWh)	23.0	24.0	24.0	25.0	26.0	26.0	27.0	29.0	30.0	31.0	32.0	32.0	33.0	35.0	35.0	36.0	40.7	46.1	52.1	57.6
Generation (GWh)	0	0	0	0	0	2,469	2,510	2,742	3,010	3,190	3,256	3,381	3,445	3,560	3,559	3,667	3,723	3,723	3,723	3,723
Capacity Revenues ($mm)	14.848	19.456	25.6	25.088	24.576	22.528	23.04	25.6	26.112	27.136	27.648	28.16	28.672	29.184	30.208	30.72	34.76	39.32	44.49	49.11
Energy Revenues ($mm)	0.00	0.00	0.00	0.00	0.00	64.18	67.78	79.51	90.30	98.88	104.20	108.20	113.70	124.59	124.56	132.01	151.63	171.55	194.09	214.24
Revenues	0.00	0.00	0.00	0.00	0.00	86.71	90.82	105.11	116.41	126.02	131.85	136.36	142.37	153.78	154.77	162.73	186.38	210.88	238.59	263.35
Fuel Costs ($/MWh)	15.30	15.68	16.07	16.47	16.88	17.30	17.74	18.18	18.64	19.10	19.58	20.07	20.57	21.08	21.61	22.15	25.06	28.36	32.08	35.41
Gas Transmission Cost ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Variable O&M Costs ($/MWh)	3.29	3.34	3.39	3.44	3.49	3.54	3.60	3.69	3.78	3.87	3.97	4.07	4.17	4.28	4.38	4.49	5.08	5.75	6.51	7.18
Fixed O&M Costs ($/KW/yr)	9.69	9.93	10.18	10.44	10.70	10.97	11.24	11.52	11.81	12.10	12.41	12.72	13.03	13.36	13.69	14.04	15.88	17.97	20.33	22.44
Fuel Costs ($mm)	0.00	0.00	0.00	0.00	0.00	42.72	44.53	49.85	56.09	60.93	63.75	67.86	70.87	75.06	76.91	81.23	93.30	105.56	119.43	131.83
Variable O&M Costs ($mm)	0.00	0.00	0.00	0.00	0.00	8.75	9.03	10.11	11.38	12.36	12.93	13.76	14.37	15.22	15.60	16.47	18.92	21.41	24.22	26.73
Fixed O&M Costs ($mm)	0.00	0.00	0.00	0.00	0.00	5.61	5.75	5.90	6.05	6.20	6.35	6.51	6.67	6.84	7.01	7.19	8.13	9.20	10.41	11.49
Decommissioning																				
Total Operating Costs ($mm)	0.00	0.00	0.00	0.00	0.00	57.08	59.31	65.86	73.51	79.48	83.03	88.13	91.92	97.12	99.52	104.89	120.35	138.17	154.06	170.05
Depreciation ($mm)	(one and one-half declining balance method					22.32	20.65	19.10	17.67	16.34	15.12	13.98	12.93	12.76	12.76	12.76	12.76	6.38	0.00	0.00
Interest ($mm)	with switch to SL)					9.19	8.50	7.86	7.27	6.73	6.22	5.76	5.32	4.93	4.53	4.14	2.17	0.20	0.00	0.00
Income Taxes ($mm)						-0.78	0.98	5.10	7.45	9.74	11.40	11.83	13.36	16.17	15.75	16.99	21.21	28.27	35.08	38.72
Year Index for Depreciation						20	19.5	18.5	17.5	16.5	15.5	14.5	13.5	12.5	11.5	10.5	5.5	0.5		
Net Income						-1.10	1.38	7.19	10.51	13.73	16.07	16.67	18.83	22.80	22.20	23.95	29.90	39.86	49.45	54.58
Capital Expenditures ($mm)					($297.61)															
EOY Book Value					297.61	275.29	254.64	235.54	217.88	201.54	186.42	172.44	159.51	146.75	133.99	121.23	57.42	0.00	0.00	0.00
EOY Debt					114.88	106.26	98.29	90.92	84.10	77.79	71.96	66.56	61.57	56.64	51.72	46.79	22.17	0.00	0.00	0.00
Working Capital																				
Cash Flow																				
Net Income						-1.10	1.38	7.19	10.51	13.73	16.07	16.67	18.83	22.80	22.20	23.95	29.90	39.86	49.45	54.58
Depreciation						22.32	20.65	19.10	17.67	16.34	15.12	13.98	12.93	12.76	12.76	12.76	12.76	6.38	0.00	0.00
Capital Expenditures					($297.61)															
Debt Cash Flow					114.88	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)	(3.83)
Working Capital																				
Net Cash Flow					($182.73)	17.39	18.20	22.46	24.34	26.24	27.36	26.82	27.94	31.73	31.14	32.88	38.83	42.41	45.62	50.75

Internal rate of return	14.65%
NPV @ 12.5% at first	$36.02

Note: Some columns are hidden for reporting purposes

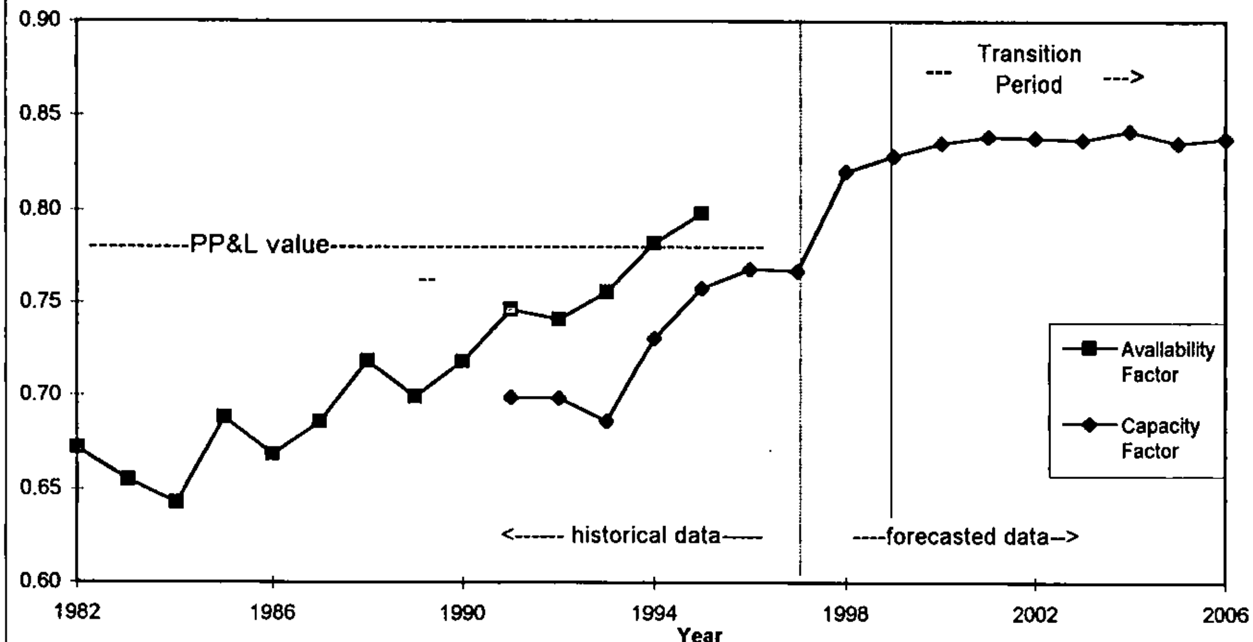
Exhibit STJ-28b

EXHIBIT STJ 29

THE EFFECT OF SPINNING RESERVES ON MARKET PRICE

	PP&L Market Price ($/MWh)	PP&L's Market Price w/o Spinning Reserves ($/MWh)	Difference ($/MWh)
1997	22.26	22.17	0.09
1998	21.38	21.26	0.12
1999	21.78	21.72	0.06
2000	22.56	22.48	0.09
2001	23.77	23.56	0.21
2002	23.92	23.84	0.08
2003	24.77	24.62	0.14
2004	25.77	25.36	0.41
2005	26.42	26.27	0.15
2006	27.20	26.90	0.30
2007	28.73	28.61	0.12
2008	29.75	29.20	0.55
2009	30.56	30.36	0.20
2010	31.57	31.32	0.25
2011	32.47	32.31	0.16
2012	33.42	33.21	0.21
2013	34.59	34.32	0.26
2014	34.91	34.71	0.20
2015	35.93	35.75	0.19
2016	36.76	36.53	0.24
Average	**28.43**	**28.23**	**0.20**

EXHIBIT STJ 30



Sources: Historical data from North American Electric Reliability Council (NERC), Generating Availability Data System (1996). Capacity forecasts from NERC Electricity Supply and Demand (1997).

Exhibit STJ-30