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Duquesne Statement No. 3

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Direct Testimony
of
Michael M. Schnitzer

Contents:

Regarding the Known and Measurable Standard and Duquesne's Market-Based Approach to Stranded Cost Calculation and Recovery

Qualifications

Q. Please state your name, position and business address.

A. My name is Michael M. Schnitzer. I am a Director of The NorthBridge Group, 950 Winter Street, Waltham, Massachusetts 02154. The NorthBridge Group is an economic and strategic consulting firm specializing in the electric and natural gas industries.

Q. Please briefly describe your educational and business background.

A. I received a Master of Science degree in management from the Sloan School of Management, Massachusetts Institute of Technology, in 1979. My concentration was in finance. I received a Bachelor of Arts degree in chemistry, with honors, from Harvard College in 1975.

In 1992, I co-founded The NorthBridge Group. Prior to that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. At NorthBridge and Putnam, Hayes and Bartlett, I have consulted for private sector clients in the electric utility, natural gas, private power, steel and coatings industries, and for several public and nonprofit agencies. My utility work has focused on resource planning, regulatory policy, finance, and industry restructuring issues. Further details of my professional and educational background are set forth in Exhibit MMS-1.

Q. Please list the regulatory commissions before which you have testified.

A. I have provided testimony or affidavits on a variety of matters before the Arkansas, Delaware, Indiana, Maine, Maryland, Massachusetts, New Hampshire, New Mexico, New York, Ohio, Pennsylvania, Rhode Island, Texas, Vermont and Wisconsin Public Utility Commissions.

Purpose of Testimony and Conclusions

Q. What is the purpose of your testimony?

A. The first purpose of my testimony is to address the proper determination of stranded costs under the Electric Generation Customer Choice and Competition Act, 66 Pa. C.S. Sections 2801-2812 ("Customer Choice Act"). Specifically, I will address the application of the "known and measurable" standard to the determination of stranded costs.

The second purpose of my testimony is to address whether Duquesne Light Company ("Duquesne" or "Company") is entitled to a price cap on generation for all years from 1999 to 2005 ("Transition Period") under section 2804(4)(v) of the Customer Choice Act. Specifically, I will address the nature of the evidentiary showings by Duquesne necessary to meet the requirements of this section.

The third purpose of my testimony is to address the calculation by Duquesne of a known and measurable CTC for each year of the Transition Period using an annual solicitation for sale of power to set the market price. I will also address the benefits of such a proposal from the standpoint of economic efficiency and fairness while

Duquesne continues to bear an obligation to serve under a generation price cap.

The fourth purpose of my testimony is to address Duquesne's proposal for a final market-based determination of stranded costs under the known and measurable standard. I will also distinguish Duquesne's market valuation proposal from a one-time administrative determination of stranded costs.

The fifth purpose of my testimony is to address the customer safeguards built into Duquesne's price cap and market valuation proposal. I will address the customer protection features of the guaranteed amortization, the ROE spillover and the early market valuation trigger mechanisms. I will also address the proper treatment of asset sales and plant shutdowns during the Transition Period.

Q. Would you please summarize your conclusions?

A. Yes, there are five main conclusions corresponding to the purposes of my testimony. First, a market-based determination of stranded costs is inherently superior to an administrative determination. Only a market-based determination can reasonably satisfy the known and measurable standard required by the Customer Choice Act. By contrast, an administrative determination of future market prices based on inherently uncertain predictions about producer and consumer behavior and forecasts of future events or trends cannot, by definition, establish known stranded costs. There is no reason to rely on an administrative determination of market prices today when a feasible and practical alternative has been proposed by Duquesne that would permit a market-based valuation to take place in 2003.

Second, Duquesne is entitled to a price cap on generation rates under section 2804(4)(v) of the Customer Choice Act for each year of the Transition Period, subject to early termination of the cap. To meet the requirements of this section Duquesne must make a prima facie showing that:

- Excess earnings achieved under the cap will be utilized to mitigate transition or stranded costs for the benefit of ratepayers under the proposed minimum amortization commitments and ROE spillover mechanism; and
- The market value of generation beginning in 2006 will be below the book value of generation and generation-related regulatory assets net of the committed minimum level of amortization.

Based on the testimony of Mr. Clayton, I conclude that Duquesne has made these two showings and is therefore entitled to the price cap through 2005.

Third, the Duquesne proposal to set customer-specific CTCs annually based on the market price of electricity as determined by the results of a market-based solicitation meets the known and measurable standard. The CTC will be calculated as a residual of the capped generation rate and the market price of power. The winning bids in the solicitation will set the market price of power for the applicable year, which in turn will establish known and measurable CTCs. This will ensure that customers, competitive suppliers and Duquesne's investors will be treated fairly during the Transition Period and that price signals will be economically efficient. By contrast—where customers are protected by a price cap—an *ex ante* calculation of CTCs based

on a one-time administrative estimation of market prices is inherently flawed. Use of this method is not consistent with encouraging competition as the resulting market price signals will be distorted. Economic efficiency requires that CTCs be set using market-based evidence of current market prices.

Fourth, the proposed market-based determination of stranded costs as of December 31, 2005 provides a known and measurable methodology to calculate stranded costs on a net present value basis. Duquesne proposes to determine the fair market value of its generating assets on the basis of prices contained in consummated market transactions in the relevant market. The final market-based valuation will be conducted in 2003 by an unbiased arbitration panel that will issue a report on its findings of market value to the Commission. Duquesne will agree to be bound by the panel's determination of market value, subject only to Duquesne's right to sell assets or sell an equity interest in a subsidiary generation company if the Commission alters or rejects the panel's finding of market value. The panel's valuation (or the valuation from such a sale or spin-off) will be known and measurable and will be used to assess whether Duquesne will have fully amortized its stranded costs under the price cap during the Transition Period.

Fifth, the proposed "true-up" methodology of the final market-based valuation protects customers by ensuring that Duquesne does not over recover its stranded costs and that customers do not "pay twice" for the costs of generation. If the market valuation is higher than anticipated, the accelerated recovery under the price cap will

be reduced accordingly. In addition, Duquesne has committed to a ROE spillover mechanism to protect customers during the Transition Period. This mechanism ensures that Duquesne will not earn more than the allowed ROE, but provides no symmetric protection to the Company for downside risk. Duquesne has a reasonable opportunity to earn a fair rate of return during the Transition Period, but still bears the risk of fulfilling its depreciation and amortization commitment. Finally, the proposed early trigger mechanisms to the final market-based valuation provide additional protection for customers if market prices rise significantly or if the committed level of depreciation and amortization is fully recovered under the price cap prior to 2003. Duquesne also has the right incentives to sell profitable generation and shutdown unprofitable generation during the Transition Period, and the potential proceeds from sale and savings from shutdown are appropriately credited to customers.

Market-Based Determination of Stranded Costs is Inherently Superior

Q. Please elaborate on your first conclusion.

A. The definition of "transition and stranded costs" contained in Section 2803 of the Customer Act is premised on each utility having the burden of demonstrating "known and 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." Only a market-based determination can reasonably satisfy that standard. An administrative process is theoretically inferior to a market-based approach and has in practice proven to be grossly inaccurate. Such an administrative determination is also unnecessary; a

feasible and practical alternative has been proposed by Duquesne that would permit a market-based valuation to take place in 2003.

Administrative Approaches are Inferior to Market-Based Approaches

Q. In theory, why should a market-based approach be inherently superior to an administrative approach?

A. In concept, stranded asset quantification seems simple enough. Utilities currently value generating assets on their books at original cost less accumulated depreciation. But when competition is substituted for regulation, the market value of generation may be less than the book value. The difference between net book value and competitive market value represents that portion of book value stranded by competitive retail access.

The key quantification question concerns the market value of generation. The value of an electric generation plant in a competitive market is what a willing buyer would pay for the right to receive the net after-tax cash flows from the plant in the future. These after-tax cash flows, in turn, depend largely on the prevailing market price for power. Thus, in an administrative determination, the critical component is a forecast of future market price. It is this requirement to forecast market price that makes an administrative determination inferior to a market-based determination.

Q. Why is that?

A. The administrative determination of market prices requires predictions about both supply and demand over a long period of time. Three sets of assumptions are critical. The first is the set of assumptions made about the new supply technology of choice: all such estimates must assume a new supply technology and its associated costs. Historically, the technology chosen has often been wrong (coal instead of gas, for instance) but even in cases where the technology type was correct, technological progress was ignored or underestimated. Costs and thus prices are usually projected assuming that technology never improves, costs never decline and efficiency gains are never realized. This type of "fixed technology" estimate has historically proven to be very inaccurate.

The second is the set of assumptions made about new supply timing and market equilibrium: administrative forecasts all assume a "need date" for new supply and typically assume the market stays in equilibrium thereafter. Both assumptions have often proven to be incorrect—the need is often later than forecast, and supply and demand subsequently get out of balance, with the result of falling market prices.

The third is the set of assumptions made about fuel prices: estimates of oil and gas prices in particular are made for a long period of time. Historically, these estimates have proven to be far off the mark—almost invariably high. As a consequence, market price projections have been overstated significantly.

Q. What is the consequence of basing market forecasts on these types of assumptions?

A. The forecasts are highly sensitive to the initial assumptions chosen by the analysts making the forecasts. When the results of the forecasts are used in an administrative context to determine or allocate value, the vastly different results obtained by changing the assumptions leads to a "battle of the experts." The consequence is a contentious and time-consuming process that seeks to substitute an administrative determination for the judgment of the marketplace.

However, there is simply no substitute for the market itself in determining market prices in the future. A myriad of individual buyers and sellers, freely taking positions and risking real dollars enter into numerous transactions. The composite of these voluntary individual economic decisions defines the market. The prices that result are by definition superior to the best documented forecast or most sophisticated model.

Q. What is the result of engaging in an adminstrative determination of stranded costs?

A. Outside of Pennsylvania, the restructuring process in other states has advanced to the stage where some state commissions have proposed an administrative determination of an allowable level of utility stranded costs. Although costs and unit performance are also at issue in these proceedings, the greatest sensitivity in the stranded cost value results from differences in the future forecasts of the market price of electricity. As the proceedings progress, the parties and the regulators often back away from a determination on an administrative basis and seek alternative solutions.

For example, in Massachusetts the Department of Public Utilities ("MDPU") originally proposed draft regulations for administratively determining stranded costs.

After holding extensive hearings in the summer of 1996, the MDPU declined to promulgate the regulations that would have implemented this procedure. Similarly, in California an administrative determination process was scrapped. The California PUC will use actual market prices from the newly established power exchange to set the CTC equivalent access charges.

In New Hampshire, the Public Utility Commission ("NHPUC") retained La Capra Associates[3] to estimate market prices and stranded generation costs. The La Capra analysis supported a "high market price" while the experts retained by utilities supported a "low market price." The NHPUC issued an order in that state's restructuring on February 28, 1997 that relied on an initial administrative estimate of market prices to establish an interim stranded cost charge, but recognized the need for a market-based "true-up" of that estimate. However, the NHPUC's Order in the case of Public Service Company of New Hampshire (PSNH) led to a PSNH claim that it had been denied a reasonable opportunity to recover its stranded costs. PSNH sought and obtained a Temporary Restraining Order against the NHPUC. The litigation over the order has been stayed as mediation efforts and settlement discussion attempt to resolve this impasse.

Q. What has been the Pennsylvania experience with the administrative determination of stranded costs?

[3] La Capra Associates has also been retained by the Pennsylvania Office of Consumer Advocate and has filed testimony on market prices and stranded generation costs in Docket No. R-00973953.

A. The Qualified Rate Order ("QRO") proceeding for PECO Energy Company ("PECO") illustrates the wide differences in value that can result from different assumptions. PECO had claimed total stranded generation plant of $3.566 billion of which it was seeking to securitize $2.435 billion under a QRO. The Commission concluded that PECO had not met its burden of proof with respect to the $2.435 billion estimate and accepted adjustments proposed by the Philadelphia Area Industrial Energy Users Group ("PAIEUG"). In total, these adjustments reduced the $2.435 billion by $1.828 billion or approximately 75 percent.

The wide bid-ask spread from the QRO proceeding has been reconfirmed in the PECO restructuring docket. PECO has sponsored testimony from three "low market price" experts. In response, the Office of Consumer Advocate ("OCA") and PAIEUG have filed testimony sponsored by "high market price" experts. Each side finds fault with the other's methodology, modeling techniques and input assumptions. The estimates confirm the bargaining positions of the parties staked out at the start of the restructuring process. Both sides support the selection of their own estimate as the basis for a one-time determination of stranded costs decades into the future. Thus, the Commission is presented with two diametrically opposed views of the likely path of future market prices and must choose.

Q. What do you conclude about market-based and administrative approaches?

A. Because expert forecasts of market price depend critically on input assumptions, vastly different results can be obtained by varying the assumptions and calculating

present values based on projections far into the future. The results are inconclusive because it costs nothing to change an assumption. Markets are different because participants risk real dollars on their assumptions. Parties may disagree on the future course of events, but in the market they must back up their predictions with cash or credit. This basic difference – bearing the cost of being wrong – separates market evidence from mere forecasts.

Administrative Determinations of Future Costs Have Failed Historically

Q. What is the historical experience with determining future prices in an administrative proceeding?

A. There is a great deal of empirical evidence available because administrative determination of market prices is not a new idea. Past administrative determinations of future "avoided costs" have been notoriously inaccurate. Relying on these administrative forecasts has resulted in the payment of billions of dollars of above-market costs by utilities to non-utility generators. The Public Utilities Regulatory Policies Act of 1978 ("PURPA") resulted in utilities and Commissions forecasting the "avoided cost" of adding new generation capacity in order to determine the prices that would be paid to qualifying facilities ("QFs") under PURPA. At that time the price of oil was high and then current forecasts called for future prices to exceed $100 per barrel.

In California, one of the first states to implement PURPA, oil was the marginal

generating resource for utilities, and the resulting avoided costs and prices offered to QFs were, in retrospect, extremely high. As a result, resources that could qualify under PURPA would still be profitable under California's standard offer prices despite their high costs of producing electricity. The standard offer contracts remained open for an extended period of time. Utilities were required to take all offered power at the posted prices from qualified sellers leading to the purchase of thousands of MWs of very costly power. The magnitude of these above-market commitments became apparent as market oil prices declined significantly throughout the last half of the 1980s, but contract prices remained fixed.

In New York, the California experience with administrative forecasting was played out with a new wrinkle. The state legislature took the additional step of mandating a floor to the administratively determined price to encourage development of the independent power industry. Under the so-called "six cent" law, New York PURPA contracts specified that co-generators be paid the greater of utility avoided costs or six cents per kWh. As oil prices declined, the "gas bubble" did not end, and load grew more slowly than forecast, the mandated pricing in these contracts proved very profitable for sellers and extremely burdensome for utilities and customers. The cost of these co-generation commitments ultimately led Niagara Mohawk ("NIMO") to threaten bankruptcy in order to bring sellers under the six cent contracts to the bargaining table. A settlement of these above-market contracts was finally signed by the producers and NIMO in July 1997, calling for payment of $3.6 billion in cash and 46 million shares of NIMO common equity to terminate or restructure the contracts.

The QF experience of California and New York was played out to lesser degrees in other jurisdictions around the nation. The worst excesses of the administered QF rates were corrected when Massachusetts, California and other states turned to competitive bidding. However, the bidding was still subject to administrative interference. The quantity to be bought was determined administratively on an own load basis and when load grew more slowly than forecast, a surplus developed and the avoided cost estimate again proved to be above the actual market price. The bid process was further hampered in states such as Massachusetts, where regulators attempted to monetize externalities and assign values to air pollutants. Again, the result of these administrative determinations of value was to artificially inflate the market price and increase the costs that would be ultimately borne by customers of the purchasing utilities.

Pennsylvania has had similar experience with avoided cost projections. While Duquesne has virtually no PURPA contract exposure, other Pennsylvania utilities bear the burden of "long-term power supply agreements as required by federal law." Contracts were signed and approved by the Commission at prices discounted from estimated avoided costs that turned out to be well above actual market prices. The above-market cost of PURPA contracts based on administered prices is explicitly recognized in Pennsylvania as Principle 15 in section 2802 of the Customer Choice Act, and again in section 2804(4)(iii). In this later section the legislature specifically exempts the "costs cancellation, buyout, buydown or renegotiation of nonutility generating project obligations of the utility" from the price caps otherwise applicable

during the Transition Period. In Pennsylvania, as elsewhere, the hangover from past administrative determinations of avoided costs has worsened the stranded cost problem.

Q. What do you conclude based on the experience in California, New York and other states?

A. Administrative determinations of cost or price are a poor substitute for the market. Our historical experience with administrative determinations reveals three types of errors repeated over and over again that correspond to the three key inputs over which the "experts" disagree. Errors in these projections have consistently been made on the assumptions about technology of choice, new supply timing and market equilibrium, and fuel prices. As a consequence, market price projections have been overstated significantly.

Markets, on the other hand, reflect the collective expectations of all market participants — participants betting their own money. Future expectations of individual parties are not always realized, but contracts freely entered into at arm's length reflect a competitive outcome that fairly allocates risk between the parties and discounts the future appropriately. Administrative determination of market price is an unproductive path which should be avoided — already the predictable debate over technology and cost, need date, and fuel prices has been joined in other Pennsylvania restructuring dockets. Administrative determination was a failure under PURPA, costing customers billions of dollars. This failure should not to be repeated in the

Pennsylvania restructuring at the further expense of customers and shareholders. Stranded costs determined from such administrative estimates of market price cannot be known and measurable.

One Time Calculation of Stranded Costs Today is Unnecessary

Q. You also state that a one-time administrative calculation of stranded cost is unnecessary. Why is this?

A. An administration determination of stranded costs is unnecessary and unwarranted because a feasible and practical market-based alternative exists and is available to the Commission. As described later in my testimony and also by Mr. Marshall, Duquesne has put forward a specific proposal for a market-based valuation of its generation in 2003. Completing a "once and for all time" stranded cost calculation today based on an administrative determination of future market prices simply places too much weight on the accuracy of the market price forecasts. Both consumer and shareholder advocates are rightly concerned that getting the market price wrong will set the level of stranded costs too high or too low, without recourse should the future turn out differently than forecast.

In the PECO restructuring proceeding, the intervenor testimony echoes this concern. The Office of Trial Staff witness Paul J. Metro testified at pp. 16-17 of his testimony that it would be possible for the stranded costs to be zero and also possible for the generation units' market value to be zero, thus indicating that all net generating plant

and CWIP were stranded. Thus, he concluded that the range of stranded costs could be $0 to $6,688,384,000. Similarly, the Office of Small Business Advocate witness Brian Kalcic proposes at pp. 7-8 of his testimony that the Commission should implement a market value/stranded cost adjustment so as to implicitly share the risks associated with the uncertainty of future market price forecasts between customers and shareholders. The risks associated with an administrative determination are unnecessary and unwarranted given the alternative of Duquesne's market-based proposal.

Q. How does Duquesne's proposal answer these concerns?

A. Duquesne's proposal for a final market-based valuation in 2003 avoids the problems of an administrative determination of stranded costs today. Consumer advocates are rightly concerned that if the forecast of market price is set too low, and utilities effectively own the generation independent of any obligation to serve following the Transition Period, then any upside value will accrue to shareholders. This is the articulated fear that customers will "pay twice" for generation: once through the CTC charges and again in the form of higher market prices following the Transition Period. Duquesne's proposal to accelerate amortization under a rate cap and make a market valuation late in the Transition Period avoids this risk. As we will demonstrate, Duquesne is entitled to a continuation of its rate cap and the customer is held harmless from the risk that Duquesne will recover too much under the cap, by operation of the ROE spillover, the final market valuation and the early valuation triggers.

Q. But, why wait to do a market valuation until 2003?

A. A market valuation of utility generation assets that are undergoing deregulation is very difficult to achieve in 1997. First, for electricity there are no clear guideposts to market value as with other commodities. Public markets are not liquid and products are not standardized. Although electricity is becoming a commodity product at the wholesale level, the market in electricity forward and futures contracts is only in its infancy. There are some nascent spot contracts for electricity such as the California-Oregon border contracts. But the physical properties of electricity make a standardized contract problematic. Electricity must be instantaneously produced and consumed as storage opportunities are limited (e.g., pumped hydro). Transmission constraints make the assessment of basis risk between different markets difficult. As a result, the current market for forward electricity contracts specify physical delivery at a particular busbar or interconnection.

Contrast the development of forward and futures contracts in natural gas. Henry Hub in Louisiana is the delivery point against which all contracts can be settled. The basis differentials for other delivery points are also established. The standard terms and conditions for allocating risk between buyers and sellers have been hammered out since gas deregulation began in the 1980s. Many financial institutions and energy companies are now quoting fixed gas prices on a forward basis for ten years or more into the future. Electricity markets are at an early stage of development compared to natural gas markets, but they will catch up.

Second, current uncertainty about future environmental regulations in a deregulated market casts a shadow over any reasoned debate about market prices. Future environmental standards for existing units are a source of great uncertainty. On June 25, 1997 the President announced new rules to be promulgated by the Environmental Protection Agency that would restrict ozone compounds and particulates resulting from the combustion of fossil fuels in power plants. If the rulemaking is implemented and its validity is upheld by the courts, the retrofit costs to existing coal units would make many of these units uneconomic at current prices. The effect of the regulations on overall market prices will depend on the cost impact to the existing supply of generation and the cost of entry of new gas-fired capacity. Thus, shutdown decisions would need to consider both the added costs of compliance with the new standards and the second order impact on market prices as other operating units are shut down and new gas-fired units are built.

Third, until the current round of industry restructuring is complete, uncertainty about the details of a fully deregulated market structure and its effect on future market prices is similarly a cause of concern. The structural overhang of continued regulation retards the development of liquidity in the power markets. The debate over bid-based versus cost-based dispatch has been joined in Pennsylvania and elsewhere. On one side certain economists argue that competitive bids for dispatch by an Independent System Operator ("ISO") will largely duplicate the cost-based dispatch seen in PJM and other tight pools today. Critics argue that bids will necessarily be higher in a competitive bid structure because utilities will seek to recover certain costs

that today are recovered in embedded cost rates. Similar debates rage over the value of capacity in a deregulated market. Will the capacity value be set by the price required to recover the cost of new combustion turbine construction or will cheaper alternatives (e.g., economic curtailment) be viable as capacity alternatives? The impact of other structural issues (e.g., load pockets and transmission pricing) on the overall level of market prices will become clearer as ISOs are formed and competitive markets develop. The uncertainty today over future market prices will be reduced as these structural issues are resolved.

Market Based Determination of Stranded Cost is a Superior Approach

Q. Please summarize your conclusion regarding the superiority of a market-based determination of stranded costs.

A. Only a market-based determination can reasonably satisfy the known and measurable standard required by the Customer Choice Act. Administrative determinations of market price are inherently unreliable and inferior to the market itself. They require key assumptions concerning what customers and competing suppliers will do over long periods of time—assumptions that are unavoidably uncertain. Past experience with avoided cost forecasts under PURPA confirms this unreliability and susceptibility to error—errors in underlying assumptions resulted in significant overestimation of market prices. A one-time administrative determination of stranded costs today can and should be avoided. An alternative market-based approach has been proposed by Duquesne that is both feasible and practical, but must wait for the

electricity markets to mature and the uncertainty over structural issues to subside.

Duquesne is Entitled to a Price Cap On Generation Under Section 2804(4)(v)

Q. On what basis is Duquesne entitled to a price cap on generation under the Customer Choice Act?

A. Section 2804(4)(v) provides that: "If an electric distribution utility rolls its energy cost rate into base rates at a combined level that does not exceed its combined level of such rates which have been approved by the Commission as of the Effective Date of this Chapter, the utility shall not be required to reduce its capped rates below the capped level upon the complaint of any party if the Commission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates."

This section of the Customer Choice Act is comparable to the treatment Duquesne received under the Fort Martin plan. Under that plan Duquesne agreed to freeze rates at current levels through 2000 and committed to a schedule of accelerated amortization of its nuclear plants and increased decommissioning funding that would offset any excess earnings from continued collection of current rates.

Duquesne Needs to Make Two Showings to Obtain Rate Cap

Q. How can Duquesne establish that any excess earnings during the Transition Period under the rate cap will be used to mitigate transition and stranded costs?

A. To make the case for holding rates at the capped levels throughout the Transition Period, Duquesne must make a prima facie showing of two propositions. The first is that a mechanism exists to ensure that if revenues under the rate cap are greater than the normal cost of service, these "excess earnings" will be utilized to mitigate transition or stranded costs for the benefit of ratepayers.

Q. Is proof of that proposition alone sufficient to satisfy the conditions of section 2804(4)(v)?

A. No, it is not. The second required showing is that the "excess earnings" available under the price cap to mitigate stranded costs are less than or equal to the stranded costs that need to be recovered. Thus, to make this additional showing Duquesne must demonstrate that stranded costs still remain in 2006 even after the "excess earnings" mitigation or, put another way, that the market value of generation beginning in 2006 is still below the book value of generation and generation-related regulatory assets net of all mitigation during the price cap period.

Q. Does this two-part showing require that Duquesne calculate a value for stranded costs as of January 1, 1999?

A. No, what is important is the potential stranded cost left over in 2006 after all "excess earnings" amortization and depreciation have been recognized on Duquesne's books. Thus, an estimate of the amount of mitigation that can be achieved under the price cap and an estimate of the range of stranded costs remaining as of January 1, 2006 are necessary to satisfy the conditions of Section 2804(4)(v). Forecasting a likely range of market prices beyond 2005 is necessary to make this latter calculation and showing.

Duquesne has Made the Appropriate Showing for Each Proposition

Q. *Has Duquesne made the appropriate showing of the first proposition?*

A. Yes. Two provisions of Duquesne's proposal ensure that excess earnings will be used to mitigate stranded costs for the benefit of ratepayers. The first of these is the minimum depreciation and amortization commitment—a commitment by Duquesne to amortize at least $1.7 billion of generation and generation-related regulatory assets during the price cap period. The second is the ROE spillover mechanism through which Duquesne commits to apply any earnings in excess of the ROE-deadband to further accelerate the $1.7 billion amortization commitment. The combined effect of the minimum amortization commitment and the ROE spillover mechanism guarantees that "excess earnings achieved under the cap will be utilized to mitigate transition or stranded costs for the benefit of ratepayers" as required by Section 2804(4)(V).

Q. Please elaborate on the minimum commitments.

A. Mr. Clayton demonstrates in his testimony that under the minimum depreciation and amortization schedule proposed, the projected book value of Duquesne's generating assets and regulatory assets as of December 31, 2005 is $535 million—reflecting $1.7 billion of depreciation and amortization between 1999 and 2005. Mr. Clayton quantified this $1.7 billion level of amortization as the amount that can be achieved under the generation price cap, while still providing the Company with an opportunity to earn a fair return on invested capital. He did this by solving for the depreciation and amortization schedule that would yield no more than an 11.5% return in each year given the forecast of revenues earned under the price cap and the projected costs over the price cap period. This is similar to the analysis performed in support of the Fort Martin plan.

Q. What is the effect of the ROE spillover mechanism?

A. As described by Mr. Clayton, the ROE spillover operates to guarantee that any excess earnings will be used to further accelerate depreciation or amortization and comply with the statutory requirement that excess earnings be used to mitigate transition or stranded costs for the benefit of ratepayers.

Q. Turning to the second showing, how do we know that these excess earnings will mitigate stranded costs and not simply reduce the book value of generation below market?

A. This is the second showing that Duquesne must make to satisfy the conditions of Section 2804(4)(v). Recall that Mr. Clayton projects a December 31, 2005 generation

book value of $535 million. Based on a present value margin analysis of Duquesne's generating units from 2006 to the end of unit life—comparing the cost of operation to the revenue each unit can earn at market—Mr. Clayton establishes that the market value of Duquesne's generation as of December 31, 2005 will range between $(47) million and $527 million -- less than the $535 million book value. Therefore, there is a prima facie showing that stranded costs will still exist in 2005 even after the $1.7 billion of committed depreciation and amortization is netted from the current book value of generation.

Q. On what basis did Mr. Clayton project the market value of Duquesne's generation beyond 2006?

A. The revenues he projects are based on a range of ceiling market prices that I have developed based on the cost of new entry beyond 2005. The support for these market prices is detailed in the following section of my testimony.

New Entry Prices Establish Price Ceiling of $34/MWh to $44/MWh in 2006

Q. What do you mean by a range of ceiling market prices?

A. I have developed an upper bound range of market prices based on the cost of entry by new construction assuming that such entry is in fact economic in 2006. These prices represent a "ceiling" on the market price, because if market prices were to exceed the ceiling it would be economic for new entrants to contest the market at those prices. As I will discuss later in my testimony, this is a conservative assumption that will

tend to overstate the range of market prices. Based on this assumption we can establish a ceiling for market prices beyond 2005 based on the costs of new construction and operation. This range of ceiling prices has been used by Mr. Clayton to estimate Duquesne's remaining stranded costs as of December 31, 2005.

Q. How did you estimate the price level necessary to permit entry?

A. I assumed that the technology of choice for new entrants in 2006 will be a gas-fired combined cycle unit, and I developed a range of break-even prices based on publicly available data on the cost of new construction. The range of prices results from alternate assumptions concerning capital cost, heat rate and the capital structure and payback requirements of the project. The details of each set of alternate assumptions are set out in Exhibit MMS-2 to my testimony[4].

Q. How did you account for gas prices?

A. I prepared a gas price forecast consistent with current forward market prices for natural gas. First, I obtained quotes for forward prices through 2005 for gas delivered to Henry Hub in Louisiana. Then, I adjusted the forward price stream to create a risk adjusted present value equivalent spot price stream through 2005. The spot price equivalent shown in Exhibit MMS-3 is $2.6/MMBtu in 2005. Finally, I assumed that the price of natural gas would escalate beyond 2005 at the general rate of inflation.

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[4] Exhibit MMS-2 contains the assumptions for a 2005 ceiling price range. As shown, I escalated the 2005 ceiling price by 2.5 percent to obtain 2006 values.

Q. How did you account for the cost of transporting gas between Henry Hub and ECAR?

A. I adjusted for the projected basis differential between Henry Hub and delivery to a new facility. located in ECAR based on a 4 year basis differential quote between Henry Hub and the TCO pool. I then assumed that the basis differential would remain the same in real terms thereafter. The calculations and the supporting data for the base case gas analysis are set out in Exhibit MMS-3.

Q. What were the resulting ceiling price estimates?

A. Exhibit MMS-2 sets out two estimates for the market price ceiling based on different assumptions. I have labeled the estimates Low and High to reflect the resulting market prices for electricity. The estimates are presented as a real levelized price (based on an 84% capacity factor) that begins in 2006 and grows with an annual estimate of general inflation of 2.5%. The Low estimate is $34/MWH ($2006) and the High estimate is $44/MWH ($2006).

Q. Why did you calculate the range of estimates based on an 84% capacity factor?

A. The estimates reflect a range of entry prices for new baseload capacity. The Duquesne generation portfolio is almost entirely composed of baseload units. As detailed in Mr. Clayton's testimony, for purposes of his margin analysis, he assumed that the Duquesne units would be fully dispatched at their equivalent availability in 2006 and beyond. Based on this dispatch of Duquesne generation, the average capacity factor of the units would be 84%. The appropriate ceiling price to use for the margin analysis is a ceiling price calculated at the same 84% capacity factor.

Q. Please describe briefly the steps in the analysis that you used to arrive at your estimates.

A. The starting point is a range of estimates of total plant capital costs of a combined cycle unit obtained from a review of industry sources. The revenues necessary to recover the capital costs with a fair return on that capital were then projected using a revenue requirements model. A real levelized charging factor was then calculated for each estimate based on the capital structure and the time horizon for recovery of the equity capital and repayment of the debt.

Q. What assumptions have you made about the appropriate capital structure?

A. In a competitive merchant plant environment the debt to equity ratio will be smaller and the time horizon for recovery will be shorter than under traditional utility financing and cost recovery assumptions. Therefore, I have assumed that a competitive capital structure would require two-thirds equity and one-third debt using an equity rate of 14% and a debt rate of 8.5% with a recovery period of 10 to 15 years. This set of assumptions results in a real levelized charging factor of 18% to 23%, depending on the recovery period.

Q. But isn't Mr. Clayton using a utility cost of capital to discount the net cash flows in his margin analysis?

A. Yes. Therefore, to be totally consistent with his analysis we should use a utility capital structure and time horizon for recovery to project the market price ceiling. Alternatively, he could use a competitive cost of capital to establish the discount rate

for purposes of his margin analysis. If the market price is projected using a higher cost of capital than is used for discounting cash flows, the result will be to overstate the market values of Duquesne's generation.

Q. How have you accounted for these differences?

A. To account for this potential mismatch of ceiling market prices and discount rates, I have completed an alternate set of calculations using the Duquesne capital structure and a recovery period of 20 years. The alternate assumptions result in a real levelized charging factor of 12%. As shown in Exhibit MMS-2, the High estimate of $44/MWh ($2006) uses the 23% charging factor, while the Low estimate of $34/MWh ($2006) uses the 12% charging factor.

Q. How did you project operating costs for the combined cycle unit?

A. The fixed and variable operation and maintenance ("O & M") estimates for operation of the combined cycle unit were based on the 1993 EPRI TAG escalated based on the general inflation rate. Estimates for administrative and general ("A & G") expenses were based on 50% of the fixed O & M estimates. The high heat rate for the combined cycle unit was based on a review of industry sources, while the low case assumes further technological progress of 0.5% per year.

The case-specific total combined cycle fixed costs for each year are the sum of the fixed O & M and the A & G expenses added to the product of the capital costs and the real levelized carrying charge. The case-specific combined cycle variable costs for

each year are the variable O & M expenses added to the product of the forecast spot gas price and the unit heat rate. The new entry ceiling prices are calculated by averaging the combined cycle fixed cost over 7350 hours (for the 84% capacity factor calculation) and adding the combined cycle variable costs.

Market Prices Could be Lower than the Ceiling Price Range

Q. You mentioned earlier that the new entry costs you derived for 2006 were ceiling prices. Do you think the actual market price is likely to be higher or lower?

A. The actual market price is likely to be lower.

Q. Why?

A. There are a number of factors that could drive the market price lower. Improvements in generation technology could reduce the new entry price level below the range I have calculated. This could arise through significant improvement in combined cycle cost or efficiency, or from a breakthrough in a different competing technology. For example, there are a number of promising new peaking technologies under development, some at projected capital costs in the $100 to $150 per kW range. As I stated earlier, a major weakness of past avoided cost projections has been the assumption of constant technology.

Another group of factors could result in the market clearing at a level below the new entry price, even in 2006. The first of these is customer demand response during "super peak" periods. During these periods, peak load in ECAR tends to decrease by

approximately 8.5% between the peak hour and the 100th highest hour. This means that with current technology building new capacity to serve these super peak hours may exceed $500/MWh. What we don't know is how many customers might be willing to reduce their consumption for a price far less than the cost of new construction. If the response is significant, the new entry date would be delayed, and 2006 prices could be lower than the combined cycle market price ceiling.

The availability of supply side resources less costly than the combined cycle unit could also cause the market to clear at lower prices than the combined cycle market price ceiling. For example, co-generation opportunities that are not yet economic at today's depressed wholesale prices, but which are cheaper than the new combined cycle, could be available in sufficient quantity to offset or reduce the need for new capacity in ECAR through 2006 resulting in lower market prices. Or, given the availability of coal energy in many hours of the year, it may be that new technology peaking capacity could be the economic choice through 2006 and the prices will not have risen to the combined cycle new entry level. Finally, opportunities in competitive markets and the interest of new entrants in building new plants for "strategic" market reasons could result in excess entry, and the creation of a new "temporary" surplus, driving market prices down again.

It is not a certainty that any of these factors will play a role between now and 2006, but there are many of them, they are not mutually exclusive, and they all operate to drive prices down, not up. Moreover, the results of Duquesne's recent solicitation

suggest that it is likely prices will be below the ceiling price range, at least for some period of time beyond 2006.

1997 Solicitation Suggests Lower Prices

Q. Does Duquesne have evidence of the market price for power during the Transition Period?

A. Yes, as detailed in the testimony of Mr. Irvin, Duquesne issued a solicitation to sell firm power on June 6, 1997 ("1997 Solicitation"). Duquesne offered to sell a minimum of 50 MW of firm power for a one-year period and a minimum of 100 MW of firm power for an eight-year period commencing on January 1, 1998.

Q. How were the winning bids selected?

A. The winning bids for the one-year contract were selected based on the highest prices offered for 1998. The winning bids for the eight-year contract were selected based on the highest prices offered on a present value basis over the contract term.

Q. Please summarize the results of the 1997 Solicitation?

A. As Mr. Irvin's testimony indicates the nominal levelized price of the winning eight-year bids was $20.19/MWh over the term of the contract. Over the same period, the real levelized equivalent bid price[5] would be $18.7/MWh ($1998). The difference

[5] Beginning in 1998 and growing at an assumed inflation rate of 2.5% per annum.

between the two price streams is that the real levelized price stream starts at a value of $18.7/MWh in 1998 and increases each year by the assumed rate of general inflation (2.5% annually) through 2005. The nominal levelized price stream starts at a higher value of $20.19/MWh in 1998 and remains the same in each year. On a present value basis the two streams are equivalent.

Q. How are the real levelized forward market prices you derived from the 1997 Solicitation relevant to the market prices Mr. Clayton used in his margin analysis beyond 2005?

A. The forward market price for power of $18.7/MWh ($1998) established by the 1997 Solicitation is very low compared to the cost of new entry. The winning bids reflect a supply/demand balance in ECAR with ample energy available most hours of the year that continues throughout the Transition Period. When supply and demand comes back into balance in the region, we would expect the market price for power to be rising toward replacement cost levels. However, the solicitation results strongly suggest that combined cycle new entry will not be economic by 2006.

Q. How did you conclude that combined cycle new entry is unlikely to be economic by 2006?

A. The winning bids for the eight-year solicitation were chosen on a present value basis. Therefore, the annual bid prices are only relevant as inputs to the present value of the entire price stream, and not as indicia of the prices in each year. Finance theory suggests that the present value of the forward price stream should be equivalent to the

present value of expected future spot prices (appropriately risk adjusted) over the same period. To derive these future spot prices, I first calculated an all-hours equivalent of the winning 75% capacity factor bid prices and discounted this price stream. I then calculated an all-hours spot price stream that was equivalent on a present value basis discounted at a risk-adjusted discount rate. In this calculation, I used a 200 basis point risk premium to solve for the equivalent all-hours real levelized spot price stream. The calculation I describe results in spot prices approximately 8% higher than forward prices in each of the eight years of the contract when presented on a real levelized basis. However, the present value of the spot price stream calculated at a higher risk adjusted discount rate is still equivalent to the present value of the forward price stream calculated a lower risk free discount rate.

Q. What does this tell us about the path of expected all-hours spot prices?

A. The analysis above is described in terms of present value equivalents. The resulting real levelized all-hours spot price is $19.4/MWh ($1998). However, this value is higher than the equivalent all-hours spot price of $17.8/MWh ($1998) derived from the winning bids for the one-year contract. Presenting the spot prices on a real levelized basis would likely overstate the expected spot prices in the early years of the contract period and understate them in the later years. Therefore, I recalculated a present value equivalent spot price stream that began at the one-year price of $17.8/MWh and grew at slightly more than double the rate of inflation through 2005. In effect, I solved for the escalation rate starting from 1998 spot prices that would make the present value of the two streams equivalent. The last year of this equivalent

stream is $25.6/MWh ($2005), representing the estimated 2005 future spot price implicit in the solicitation results. Exhibit MMS-4 sets out the derivation of the 2005 future spot price estimate.

Q. What do you conclude based on this analysis?

A. The 1997 Solicitation suggests that there is a significant gap between the likely 2005 spot market price and the market ceiling established by the cost of new capacity. The all hours spot price equivalent I calculated for 2005 was $25.6/MWh ($2005); adjusting to an 84% capacity factor basis would increase this spot price equivalent to $26.5/MWh ($2005). This $26.5/MWh value is still far below even the Low estimate of the market price ceiling based on cost of economic new entry in 2006. Therefore, it is highly unlikely that new combined cycle capacity would be economic to build in 2006 based on the results of the 1997 Solicitation, particularly if required new entry prices are at the high end of the range.

Q. Have you assessed the impact of new combined cycle capacity not being economic until after 2006?

A. Yes. I have developed two additional market price estimates based on the cost of new entry in the year 2010 under the High and Low competitive capital structure assumptions shown on Exhibit MMS-2. In each case, I calculated a spot price trajectory between 2006 and 2010 required to reach the appropriate new entry price in 2010. These two additional cases are summarized on Exhibit MMS-5.

Q. What do the results of these additional cases show?

A. Unsurprisingly, the real levelized prices of these delayed entry cases are lower than their corresponding 2006 entry cases. In the High case, the real levelized price falls from $44/MWh to $41/MWh under delayed entry assumptions. In the Low case, the price falls from $37/MWh to $35/MWh, a smaller reduction.

Q. What do you conclude from this delayed entry analysis?

A. Because market evidence indicates that economic combined cycle entry in 2006 is unlikely, particularly at the high end of the new entry range, the $44/MWh High price estimate is unrealistically high. By using the High estimate of $44/MWh Mr. Clayton's margin analysis likely overstates the market value of Duquesne's generation and thereby understates the remaining stranded costs. Based on the delayed entry case, $41/MWh is a more realistic figure for the High case, which would reduce Mr. Clayton's year-end 2005 market value from $527 million to $278 million, and increase remaining stranded costs by approximately $249 million.

Q. Mr. Schnitzer you have discussed the 1997 Solicitation results only in the context of post-2005 prices. Is the level of market prices between 1999 and 2005 important for any other reason?

A. The principal value of 1999 to 2005 prices is as evidence of the likely market price in 2006 and beyond. That is because market prices during the Transition Period do not have much effect on the amount of amortization that can be realized under the price cap from sales to existing customers. This amount depends mainly on the revenues

that can be earned under the price cap and the cost of producing that power. This is because Duquesne is proposing to calculate its CTC as a residual from the generation cost of service, and thus the combination of market prices and the CTC will result in revenues equal to current rates times purchases by jurisdictional customers. This is true even if the customer has chosen an alternative generation supplier. A higher or lower market price during the Transition Period will only change the proportions of revenue recovered through the CTC and through sales at the market price. Total revenues will remain unchanged as long as the market price has been used to set the CTC. Market prices will have an effect on off-system sales margins, but their contribution to the $1.7 billion depreciation and amortization commitment is quite modest.

Q. You have used the all-hours expected spot prices from 1999 and 2005 to assess the likelihood of new combined cycle entry in 2006. What other use is made of the all-hours expected spot price stream?

A. Mr. Karl's testimony describes how he uses the escalating all-hours spot price stream as an input to calculate the prices that would be faced by Duquesne's generation in the market during the Transition Period. Mr. Karl uses this spot market price stream to determine the dispatch of the Duquesne units during the Transition Period and the resulting off-system sales and purchases are reflected in Mr. Clayton's projections of the costs and revenues of operating Duquesne's system.

Use of Market Price Estimates is Appropriate for Section 2804(4)(V) Showing

Q. Why is appropriate to use these market price estimates to determine stranded costs as of 2005?

A. The purpose for which these estimates are being used by Mr. Clayton is not to make a claim for a one-time administrative determination of stranded costs in that amount. Rather, he is seeking to establish the more limited claim that Duquesne is entitled to the rate cap under section 2804(4)(v) of the Customer Choice Act. The actual determination of stranded costs under the Duquesne proposal will be completed in 2003 using a market-based valuation.

I have provided a high and a low estimate of the market price ceiling established by the entry costs of a combined cycle unit coming into service in ECAR in 2006. In discussing the uncertainties surrounding the input to these estimates, I concluded that resolution of the uncertainty would likely result in a decrease in the costs of new entry or a delay in the year of entry beyond 2006. Indeed, the results of the 1997 Solicitation suggest that 2006 is highly unlikely as a year of combined cycle entry.

However, over the full range of post-2005 ceiling prices, Mr. Clayton demonstrates that the book value of generation and generation-related regulatory assets remaining at the end of 2005 (after netting the committed level of amortization) will exceed the market value of generation. Thus, even under conservative assumptions Duquesne has demonstrated that it will have stranded costs remaining in 2005 even after

applying all "excess earnings" under the price cap to stranded cost mitigation. Moreover, even in the unlikely event that prices rise, or stranded costs are amortized more quickly than forecast, Duquesne has proposed specific market-based early valuation triggers that protect customers from a continuation of the rate cap for too long and recovery of too much stranded costs by Duquesne. Thus Duquesne has made both parts of the two part showing, and is entitled to a price cap through 2005.

Market Based CTCs are Superior

Q. How does the calculation of stranded costs relate to the setting of CTCs?

A. In Pennsylvania utilities are permitted to collect their stranded costs through a competitive transition charge or CTC. Section 2808(A) of the Customer Choice Act provides in part that: "To provide each electric utility with an opportunity to recover its transition or stranded costs following the Commission's determination under subsection (c), every customer accessing the transmission or distribution network shall pay a competitive transition charge to the electric distribution company in whose certificated territory that customer is located."

In the restructuring filings prior to August 1, 1997 (i.e., PECO, Pennsylvania Power and Light and the GPU Companies) the parties have performed a one-time calculation of stranded costs as of the beginning of the Transition Period. This present value of stranded costs is then used to calculate a CTC revenue requirement over the Transition Period to establish CTC rates for each class.

Q. How does Duquesne's calculation of CTC's differ from the approach of the other utilities in Pennsylvania?

A. Duquesne will sell a substantial block of power in each year of the Transition Period in order to establish an objective market price. The terms and conditions of the sale will be similar to the one-year 1997 Solicitation. These annual solicitations will determine the market value of power and the customer's opportunity cost of leaving Duquesne in that year. The resulting prices will be used to determine customer-specific CTCs.

Administratively Determined CTCs are Inferior

Q. Does the process proposed by the other Pennsylvania utilities send the right price signals to customers and suppliers?

A. No, not when customers have the protection of a rate cap during the Transition Period. For example, the methodology offered by PECO in its restructuring case proposes to calculate the CTC revenue requirement and levelize it over the seven-year Transition Period. Because the Customer Choice Act requires utilities to unbundle rates, PECO also proposes to calculate the "market rate" it will offer to generation customers as a residual after deducting the levelized CTC from the generation price cap. As the OCA points out in the testimony of witness Lee Smith (pp. 8-11), the PECO calculation of the "market rate" will set the implicit market price signal too low, and, assuming market prices increase over time, this disparity will widen during the Transition Period.

A similar criticism is voiced by PAIEUG in the testimony of witness Stephen J. Baron (pp. 27-34). Both witnesses make the point that if PECO establishes a levelized CTC based on a one-time determination of stranded costs, customers will be sent the same price signal for each year of the Transition Period, even as the actual market price for power changes over time. Customers always have the protection of the PECO generation rate cap, and if the residual "market price" calculated is less than the actual market price, customers will stay with PECO. This result, as the OCA and PAIEUG point out, can hinder competition and retard the development of a healthy retail electricity market. As OCA witness Lee Smith states at p. 8 "The company's proposed generation component, which is fixed for the transition period, does not bear any relationship to the cost of providing power to the retail customer."

Q. Does the OCA offer a better alternative to the PECO CTC methodology?

A. No, the OCA simply proposes to substitute an administratively determined "avoidable generation component" that increases over time. This component however is subject to the OCA's own criticism, that it does not bear any relationship to the cost (i.e., purchased at market) of providing power to the retail customer.

Q. Does PAIEUG offer a better alternative to the PECO CTC methodology?

A. No, PAIEUG simply proposes to replace the administratively determined "market price residual" with an administratively determined "CTC residual." At p. 33 of his testimony witness Baron states: "Under the alternative approach, which I am recommending, estimated market prices for each of the seven years would be

subtracted from the unbundled generation component, leaving a residual value that would then become the CTC for each year. Since market prices change during the seven year transition period, increasing over time, the residual CTC would also vary (though fixed for each year at the time of the unbundling) during the seven year period...Under this approach, the market rate component of PECO's unbundled rate schedules would reflect expectations for market rates in each year of the transition period."

Both the OCA and PAIEUG are carrying over the administrative determination of stranded costs to an administrative determination of CTCs and implicit market price signals sent to customers. In essence, both the OCA and PAIEUG propose to administratively estimate – in advance – the market price to customers that continue to take generation service from PECO, and do not propose to adjust this price to reflect actual changes in the market.

Q. Why is that a problem?

A. Under a price cap, the net opportunity cost[6] to a utility of not selling generation to an existing customer at capped embedded cost generation rates will change. If the market price rises, the net opportunity cost falls and vice-versa. Similarly, for customers, their opportunity cost of not purchasing power from competitive suppliers

[6] The net opportunity cost is the difference between embedded cost generation rates and the current market price.

of generation will rise and fall depending on the market price of power. Only by setting the CTC based on the current year's market price are the customer and competitive suppliers faced with the right price signals.

Estimating the Price Signal in Advance Distorts Economic Behavior

Q. Why is it important to use the current market-determined price to set the CTC price signal?

A. Consider the following illustrative example where the incumbent utility is subject to a rate cap. In year 1 the generation rate cap is 6.0 cents/kwh and the market price for year 3 is forecast to be 2.5 cents/kwh. The utility fixes the CTC for year 3 in advance at 3.5 cents/kwh (6.0-2.5) based on the forecast market price. In year 3 the actual market price turns out to be 3.0 cents/kwh, but customers choosing whether to leave their incumbent supplier are still faced with the fixed price signal of 2.5 cents/kwh. By fixing the CTC artificially high based on an erroneous market price forecast customers will not leave the utility in year 3 because the market price has risen above their price signal of 2.5 cents/kwh. Competitive suppliers will be disadvantaged by the combination of the rate cap and the CTC. Customers will choose to stay with their incumbent supplier even if a competing supplier could discount the market price two mills below 3.0 cents/kwh.

Conversely, suppose the same example as above, except that in year 3 the actual market price turns out to be 2.0 cents/kwh. Customers choosing whether to leave

their incumbent supplier are still faced with the fixed price signal of 2.5 cents/kwh. By fixing the CTC artificially low based on an erroneous market price forecast customers will leave even when it is not economic to do so. A competing supplier could sell to customers at a premium of two mills above the market price of 2.0 cents/kwh and still offer them savings. The incumbent utility will be disadvantaged by not being able to resell the lost load above the current market price of 2.0 cents/kwh

Duquesne's CTC Methodology is Superior and Sends the Right Price Signals

Q. Why is the Duquesne CTC methodology superior to the administrative proposals already advanced in Pennsylvania?

A. Duquesne's proposal properly reflects the uncertainty in future spot market prices. As the market price for power changes over time, the net opportunity cost to Duquesne of not selling generation to an existing customer at capped embedded cost generation rates will change. If the market price rises, the net opportunity cost falls and vice-versa. By having the opportunity to sell the lost load in the market, at the market price, Duquesne offsets the lost opportunity to sell at the capped generation rate by the revenues obtained at current market. The customer's CTC is established annually based on the then current market price for firm power determined in the most recent annual solicitation. In each year of the Transition Period the customer faces a price signal based on the difference between that year's market price and the generation rate cap. Based on this price signal, customers can choose to leave

Duquesne when the price of a competitive supplier is favorable compared to Duquesne. Customers can return to Duquesne as a generation supplier at unbundled rates and may do so if the unbundled generation rate is competitive with market.

Market Prices are Required to Establish CTCs

Q. What do you conclude about establishing CTCs under a rate cap?

A. Where customers are protected by a rate cap, determining CTCs on a one-time *ex ante* basis using an administrative determination of stranded costs and estimated market prices is inherently flawed. The correct price signals will only be sent if CTCs are determined as a residual of the generation price cap and the current market price determined from market evidence.

Q. How does this customer-specific CTC approach proposed by Duquesne meet the known and measurable standard?

A. The market-based RFP approach determines a known and measurable one-year market price that is used to calculate stranded costs based on the difference between market and the customer's current embedded cost generation rate.

2003 Market-Based Valuation Meets Known and Measurable Standard

Q. Please explain how the market-based valuation methodology permits a final valuation of stranded costs consistent with the known and measurable standard.

A. The Customer Choice Act requires a calculation of stranded costs to meet a known and measurable standard. The conclusion I reached in the first part of my testimony was that a market-based determination of stranded costs was inherently superior to an administrative determination. I concluded that only a market-based approach could reasonably satisfy the known and measurable standard required by the Customer Choice Act. However, because markets for standardized commodity contracts such as forward and futures contracts are only now beginning to develop and environmental and restructuring uncertainties have not been resolved, a market valuation for the years beyond 2005 should be deferred until later in the Transition Period.

Accordingly, Duquesne has not sought to calculate a final value for stranded costs as of January 1, 1999 as have the other utilities in Pennsylvania. Duquesne has instead shown that it cannot fully recover its stranded costs through application of "excess earnings" through 2005 under the rate cap.

Public sources of objective market data will likely be available late in the Transition Period that will permit a known and measurable valuation of stranded costs as of December 31, 2005. The final market valuation proposed by Duquesne would be scheduled to begin in 2003. The intent of this proposal is to complete the final market valuation by the end of 2003 in time to permit any changes to the CTC to become effective January 1, 2004.

Final Market Valuation Based on Independent Appraisal

Q. How would a final market valuation be conducted?

A. The Duquesne proposal has three basic elements. First, the final valuation will be based on objective evidence of market values, not market price forecasts. Second, the final valuation will be conducted by an unbiased arbitration panel that will submit a final valuation report to the Commission. Third, upon receipt of the valuation report, the Commission will retain the final authority to determine the market value of Duquesne's generation assets and, hence, stranded costs under the Customer Choice Act.

Q. Please elaborate on the first element of the Duquesne proposal.

A. The market value of Duquesne's generation will be set on the basis of actual market prices contained in consummated market transactions in the relevant market, such as futures contracts, forward contracts or asset sales. To ensure the availability of market evidence, Duquesne will commit to sell long-term firm power under a competitive solicitation to provide evidence of long-term forward prices. The sale of power by other utilities will be considered as market evidence if such sales are in the relevant market and, as to asset sales, are for comparable generation assets within the relevant power market.

Q. Please elaborate on the second element of the Duquesne proposal.

A. A three-member arbitration panel will be selected to ensure a fair and unbiased composition. Duquesne will select one member, a consumer representative (such as the Office of Consumer Advocate or the Commission staff) will select the second member, and these members will select the third member. The panel will base its decision solely on objective evidence of market values as described in the first element.

Q. How would the panel calculate the final market value?

A. The actual methodology would be up to the panel's discretion. One methodology might determine the final market valuation of Duquesne's remaining generation assets from 2006 onward using a net present value calculation of after-tax cash flows, based on the market evidence gathered by the panel. In such an analysis it is anticipated that the panel would use the then current best estimates of the cost of capital, unit availability, capital expenditures, fuel costs, and operating expenses in making a determination of value.

Q. What input from the public will be permitted?

A. To ensure public participation, any interested party may submit evidence of such market values to the panel. After considering the evidence and deliberating, the panel will issue a written report detailing its findings on market value. This written report will be submitted to the Commission for review and public comment.

Q. Please elaborate on the third element of Duquesne's proposal.

A. Upon receipt of the arbitration panel's report, the Commission may solicit public comment and render its decision on the market value of Duquesne's generation, and hence on Duquesne's stranded costs, pursuant to traditional hearing procedures. In reaching its decision, the Commission will, of course, not be bound by the panel's findings on market value. Nor, does Duquesne propose to bind any intervening party to these findings. All intervening parties may contest the Commission's determination of market value, whether or not such determination is based on the panel's findings or other evidence.

Q. Will Duquesne be bound by the panel's finding of market value?

A. Duquesne will commit to bind itself to the panel's findings subject only to the following condition: if the Commission rejects the panel's findings and substitutes a market valuation that is adverse to Duquesne, Duquesne will be permitted to establish market values through the sale of some or all of its generating assets or the sale of an equity interest in a new corporation ("Genco") to which Duquesne's generating assets would be transferred. If Duquesne sells individual generating assets, the sales prices will determine the value of only those assets sold by Duquesne. If Duquesne sells an equity interest in Genco, the price will set the value of all generating assets owned by Genco. The market values established through the asset sale or the generation company spinoff would be used to calculate the final market value of those generation assets.

Q. Does Duquesne have any other recourse if the Commission's decision is adverse?

A. If Duquesne chooses not to sell assets or an equity interest in Genco, it may contest the Commission's rejection or modification of the panel's findings by pursuing an appeal of the Commission order or requesting further hearings (or rehearing) before the Commission.

Q. What is the ultimate purpose of the final market valuation?

A. The final market valuation will provide objective market evidence of Duquesne's stranded costs as of the end of the Transition Period. If this valuation demonstrates that Duquesne will have fully amortized its stranded costs prior to the end of 2005, then Duquesne will reduce the Transition Period accordingly and cease to collect a CTC from its customers. This will ensure that customers do not reimburse Duquesne for more than its stranded costs. Alternatively, if this valuation confirms that Duquesne cannot fully recover its stranded costs prior to the end of 2005, the final market valuation will provide the basis for any further relief that Duquesne is entitled to seek under the Customer Choice Act or pursuant to the protections provided by other laws.

Q. Doesn't Duquesne's proposal for an arbitration panel charged with preparing a market valuation fall prey to the criticisms you have made about administrative forecasts?

A. No. The key distinction is in the nature of the valuation: the panel proposed by Duquesne will prepare its valuation based on actual market prices contained in transactions between willing buyers and sellers, such as the winning bid prices revealed in a Duquesne solicitation or the prices revealed in other forward market

buy/sell transactions. The practice of forecasting that I criticized earlier is something quite different: the prediction of future market prices based on a myriad of assumptions about future market behavior of individual agents that collectively determine supply and demand. It is these assumptions that routinely prove materially inaccurate, and often prove to be grossly so.

These assumptions suffer from a related infirmity. Given that they represent the predictions of economists and experts, rather than the risk-taking actions of market participants, they provide Duquesne's investors no reasonable ability to hedge the financial effects of using such assumptions to set the level of stranded costs, and hence CTC rates. For example, if economists predict market prices of $40/MWH, but market participants are not willing to purchase power at that price, Duquesne cannot effectively sell power in an effort to hedge the risk that such market price estimates will prove inaccurate.

Under Duquesne's proposal, only the prices contained in actual market transactions or public offers to buy and sell power would serve as the basis of stranded cost calculations, thus providing Duquesne a reasonable opportunity to recover its stranded costs by accepting the offers of market participants to purchase power at those prices. The use of an independent panel simply provides a neutral party with specific valuation expertise to consider the relevant market data.

Market Valuation Should Be Deferred Until Later in the Transition Period

Q. Assuming you are correct that only a market-based valuation should be used to establish stranded costs, why not simply use the market price data available today to establish the value of Duquesne's generating assets?

A. There are two reasons why the market valuation should be deferred until later in the Transition Period. The first is that the market for long-term power in ECAR today is sufficiently illiquid that there are not sufficient long-term transaction data to confidently establish a market value. The results of the 1997 Solicitation provide some market data, but these 8-year bids are not of sufficient term to establish a market value for Duquesne's generation.

Q. Will this situation change in the foreseeable future?

A. Yes, as I stated earlier in my testimony, I expect that electricity market will follow other deregulated markets, particularly natural gas in developing a more robust and liquid market for forward and futures contracts. In addition, generating asset sales within ECAR may answer the question of whether, as some have suggested, there is a premium associated with asset ownership that would cause values calculated on the basis of market prices for power to understate asset value. In any event, even if none of this evidence does materialize by 2003, the arbitration panel will be able to rely on the market evidence from Duquesne's long-term solicitation in 2003. Therefore, in all cases the final market valuation will be based on actual transactions and hence the final stranded costs will be known and measurable in a meaningful sense.

Q. What is the second reason for deferring the market valuation?

A. The second reason has to do with the price cap and a customer's right to service at the price cap during the Transition Period. As has already been described, the price cap approach to stranded cost recovery under the Customer Choice Act requires that two questions be addressed:

- How much "excess earnings" are available to mitigate stranded costs during the price cap period; and
- Are there stranded costs remaining at the end of the price cap period after taking account of the "excess earnings" mitigation -- does the book value still exceed the market value of generation?

It is clear that the required valuation is as of the end of the price cap period -- not at the beginning. Given that the valuation date is as of the end of the price cap period, it is preferable to delay the valuation process to a date much closer to the valuation date. To perform the valuation any earlier, even with market data, is to invite unnecessary risk and uncertainty associated with the volatility in market prices. If we ask the market today, we will get its best estimate of post-2005 market price, an estimate with a high variance (i.e., a greater level of uncertainty). But if we ask the market in 2003, we will get a more certain estimate of post-2005 prices. Duquesne's proposal properly recognizes that a later valuation of generating assets as of 2005 is preferable to an earlier valuation as of 2005. This later valuation is clearly more likely to produce a "known and measurable" calculation of the net present value of stranded

costs over the life of Duquesne's generating assets, as required by the Customer Choice Act.

Proposed Final Market Valuation is Fair to Customers and Shareholders

Q. Why is a final market valuation fair to customers and shareholders?

A. Mr. Clayton has committed Duquesne to a minimum level of accelerated depreciation and amortization and coupled this with the guarantee of an ROE spillover. This is complemented by the "true-up" of the final market valuation. This ensures that Duquesne does not over recover its stranded costs and that customers do not pay twice for the costs of generation. If the market valuation is higher than the committed level of book value (appropriately adjusted for capital expenditures) then the accelerated recovery under the price cap will end before 2005. A negative residual value determined by the final market valuation will give Duquesne the opportunity to request that the Commission extend the price cap to allow further recovery.

Q. When would an earlier valuation date than 2003 be appropriate?

A. Two events would trigger an early final market valuation process to determine the residual market value of the generation assets. First, if the long term market price of power rises significantly prior to 2003, then it is possible that the residual market value at the end of 2005 will significantly exceed the unamortized book value of generation and early termination of the CTC might be possible. The proposed solution is to establish market price triggers for the years 2001 and 2002, and to accelerate the

final market valuation to 2001 or 2002 if the trigger prices are exceeded. Mr. Clayton's testimony includes the calculation of the "early trigger" market prices for generation for each year. The evidence to determine whether the market price exceeds the trigger price is Duquesne's annual solicitation for sale of firm power held in 2000 and 2001 to established the customer specific CTCs for 2001 and 2002. Second, as described by Mr. Clayton, if Duquesne has fully completed its scheduled $1.7 billion amortization prior to 2003, then an immediate final market valuation can take place to determine if CTC collection should be reduced or eliminated.

Q. Do either of the early triggers settle the issue of residual market value?

A. No. The triggers merely accelerate the final market valuation mechanism. That mechanism, and not the triggering events, determines the residual market value.

Asset Sales Should Recognize Margin Contribution Under Price Cap

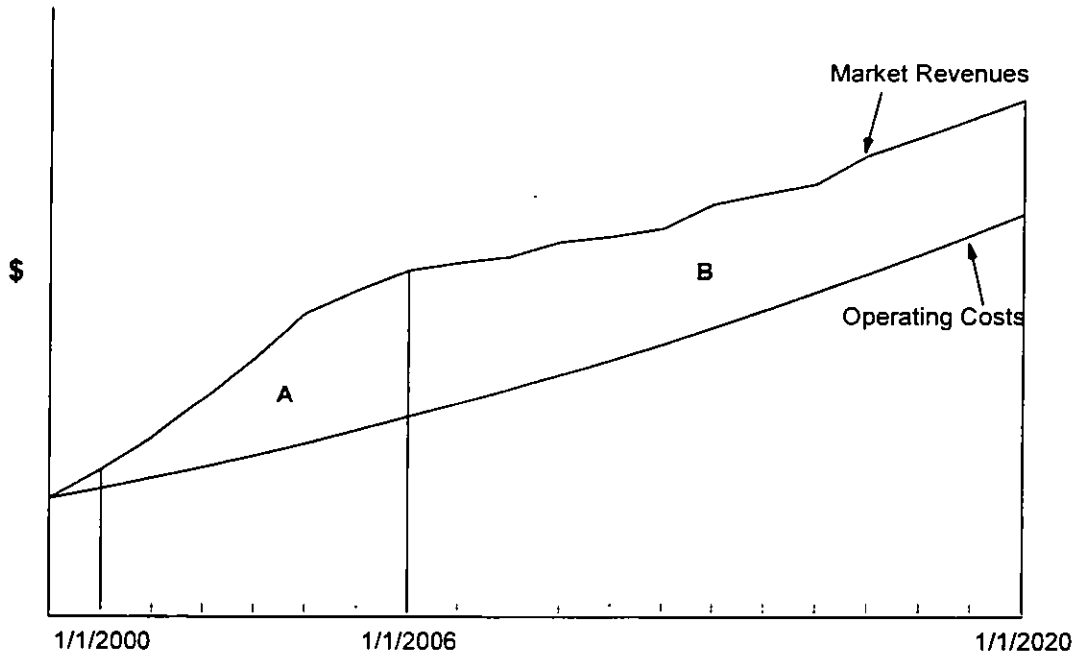
Q. Please describe the issues that arise as a result of generating asset sales.

A. Sales of generating assets during the Transition Period raise complicated valuation issues while the rate cap remains in place. During the Transition Period Duquesne effectively earns generation revenues equal to the generation rate cap based on a combination of CTC revenue and market generation revenue. This combined revenue level is what has allowed Duquesne to commit to accelerated amortization of generation and regulatory assets. The question is how to treat the proceeds from asset sales for purposes of writing down the book value of generation.

Q. When an asset is sold doesn't one simply credit the purchase price against the book value of the asset and any associated regulatory assets?

A. No, that would ignore the effect of the rate cap. The operating margin from generation during the Transition Period (i.e., the difference between to go costs and market revenues) helps to fund the accelerated amortization that Duquesne has committed to as part of this proposal. The contribution to amortization by sales made under the rate cap prior to December 31, 2005 is part and parcel of the stranded cost package. With an asset sale, this operating margin contribution is lost to Duquesne and goes instead to the new generation owner. Thus, if an asset is sold, the foregone operating margin contribution through the end of 2005 must be deducted from the sale proceeds before crediting against book value.

This can be conceptualized more easily as an asset sale coupled with a contract back through 2005. If Duquesne sold a generating asset that would otherwise have provided power at an average to-go cost of $15.00/MWH through 2005 then the operating margin from that output will be reflected in the purchase price. As well, any residual market value in the asset beyond 2005 will also be reflected. If the purchaser agrees to sell the output back to Duquesne at the "to go" costs during the Transition Period, then the purchase price paid will be automatically reduced by otherwise foregone operating margin over this period, discounted to the date of purchase. This is illustrated by the graphical example below. The area A represents the contribution margin within the Transition Period.



Area B represents the contribution margin that determines the market value of the asset beyond 2005. Any credit against the book value must separate the sources of value to the purchaser and only credit the value of Area B in order to avoid over crediting.

The above described adjustment to sales proceeds protects investors from double counting Transition Period operating margin. In a similar vein, the book value of the plant must be adjusted downward to equal the present value of the estimated 2005 book value to ensure that customers receive the full benefit of the committed amortization.

Q. Please summarize your conclusions regarding asset sales.

A. The proposed treatment of asset sale proceeds is necessary to properly account for the residual market value in the asset sale price. This accounting can be accomplished through an explicit contract back from the purchaser at the unit's to go costs for the remainder of the Transition Period. Alternatively, an implicit contract could be calculated to remove this source of value from the purchase price. This treatment satisfies the known and measurable standard. Similarly, the proposed book value adjustment also satisfies the known and measurable standard.

Duquesne's Proposal Provides Customers with Any Benefits From Economic Shut Downs

Q. The market prices determined by the 1997 Solicitation are quite low: how does Duquesne's proposal address unit shut down during the Transition Period?

A. Let me first describe the two principles which define a properly structured shutdown analysis. The first principle is that a proper analysis should only consider the true avoidable costs of continued operation. The second principle is that, given the irreversibility of a shutdown decision for a nuclear unit or some coal units, the analysis should consider the "option value" of continued operation.

Q. Please address the first principle regarding avoidable costs.

A. A basic economic principle is that sunk costs should play no role in the decision of whether to continue to operate a plant, or to shut it down. The reason for this is that

sunk costs cannot be "saved," and thus are irrelevant to the decision of whether it is cheaper to continue to operate a facility, or to shut it down. While the principle may be clear, it is sometimes less clear whether a particular cost is sunk or not. For some categories of cost this determination is quite straightforward. For example, the net book value of a facility is clearly a sunk cost, while the projected cost of fuel not yet purchased is clearly not a sunk cost.

While it is tempting to generalize from these examples that all dollars already spent are sunk, and all those not yet spent are not – this is in fact not correct. Two categories of costs "not yet spent" may nevertheless represent sunk costs for the purposes of economic analysis. First, costs which have not yet been incurred but for which there is an obligation or commitment to fund independent of whether the generating facility remains open or shuts down. Obligations such as contractual commitments to pay lease expenses, fuel or equipment costs would all – net of salvage value – represent sunk costs. Second, allocated operating costs which are assigned to a particular project or facility using some accounting convention, rather than being a cost directly incurred by the facility, may represent – at least in part – sunk costs.

The common feature of these two exceptions is that they represent operating costs which are not avoidable by shutting down the facility. Contractual purchase obligations, net of salvage or resale value, are not avoidable. Allocated or assigned costs, or a portion thereof, may not be avoidable. Any such costs that are not

avoidable by closing the facility, even though the cash costs have literally not yet been spent, are still considered to be sunk costs for purposes of economic evaluation. Thus, a properly structured economic analysis must carefully distinguish between those operating costs that are avoidable, and those that are not.

Q. Please elaborate on your second principle related to option value.

A. Many types of facilities have the characteristic that once shut down they cannot be restarted except perhaps at great economic costs. Other facilities can be shut down and later reopened at will with little or no economic penalty. For this latter type of facility the economic analysis of continued operation is quite simple. The avoidable costs for a period of time (e.g., a year) can be compared to the anticipated revenue if the facility operates. If avoidable costs exceed anticipated revenues the facility can be closed for the period. This decision can be made without consideration of subsequent periods, because the decision to shut down today has no implications for the ability of the facility to reopen tomorrow should anticipated revenue then exceed avoidable cost.

Q. What about facilities that once shutdown cannot be reopened or can be reopened only at great cost?

A. For these facilities a simple one period analysis is not adequate. A decision to remain open for one period (a year or a fuel cycle) must consider not just the profit or loss from revenues less avoidable costs in that period, but also the value of the option to remain open the next period. Similarly, a decision to shut down at a particular time

carries with it not only the economics of the next period, but also forecloses the option to operate the facility in all subsequent periods.

Thus for this second type of facility, a decision to remain open in one period preserves the option – but not the obligation – to remain open in subsequent periods. A decision to close the facility cancels the option to operate the facility in all subsequent periods. In some cases it may make sense to operate the facility at a loss (avoidable costs in excess of revenues) for some length of time to preserve the option to make money in the future. In such cases the value of the option to operate in the future must exceed the cost of preserving the option.

The value of the option is an empirical question. It depends on the avoidable cost of operating the facility relative to the expected revenue, but also on the uncertainty or volatility of the revenue. Other things being equal, the more uncertain the revenue, the more valuable the option to remain open. For facilities facing an irreversible shutdown decision this option value must be included in an economic analysis of continued operation.

Q. How does Duquesne's proposal deal with shutdown?

A. The question is how to deal with the closure of a generating plant that was economic to operate at the time of the Commission's order, but becomes uneconomic to operate during the Transition Period. Under Duquesne's proposal two things are clear. First, Duquesne has the right incentives to shut down uneconomic units, appropriately considering option value. Second, customers receive any benefits from economic

shutdown because any "excess earnings" that result from the shutdown will be used to further accelerate the amortization of stranded or transition costs and help end the Transition Period early.

Q. Please elaborate on Duquesne's incentives to shut down uneconomic generation.

A. Duquesne continues to have an obligation to serve at capped rates during the Transition Period. If the shutdown decision is the result of operating costs that are higher than expected at the time of the restructuring order, then Duquesne must buy at market to cover the lost output. Duquesne will compare the actual avoidable to go costs of operating the unit against market price in making the shutdown decision. If purchases at market are less expensive (appropriately considering option value) then Duquesne will shut the unit down and discharge its obligation to serve from the market. This cost to cover at market may be in fact be greater than the anticipated operating costs for the unit at the time of the restructuring order. However, since actual costs have risen, and Duquesne is at risk for increased market costs due to the shutdown, it has the right incentives to do the analysis correctly and shut down the unit when it is economic to do so.

Conversely, if the shutdown decision is the result of market prices that are lower than expected at the time of the restructuring order, then Duquesne lowers its cost of meeting its obligation to serve under the rate cap. This lower cost allows Duquesne a greater opportunity to earn its allowed return under the price cap and to further accelerate the recovery of stranded and transition costs under the ROE spillover. Therefore, in this case too, Duquesne has the right incentives to do the analysis

correctly and shut down the unit when it is economic to do so.

Q. Please elaborate on the customer benefits and protections if Duquesne shuts down a generation unit.

A. As discussed above, Duquesne has the right economic incentives to do the shut down analysis correctly. If shutdown results from higher than anticipated costs or worse performance, customers nonetheless receive the benefit of the guaranteed amortization, whether or not Duquesne is able to earn its allowed return. If shutdown results from lower than expected market prices, customers receive the benefit of any cost reduction through the ROE spillover. Finally, the operating margin from generating assets that are shut down during the Transition Period is effectively valued at zero, thus resolving the question of residual market value. Duquesne will not end up owning a potentially valuable asset after the Transition Period.

Q. Please summarize your conclusion with respect to plant shutdown.

A. The proper incentives to shut down a plant when it is economic to do so combined with the ROE spillover mechanism ensure that Duquesne will minimize, but not over recover its stranded costs through economic shutdown. The adjustments to the book value of generation and regulatory assets in the event of a plant shutdown are known and measurable.

Summary

Q. Please summarize your testimony.

A. I have five major conclusions concerning the known and measurable standard and Duquesne's market-based approach to stranded cost calculation and recovery:

- A market-based determination of stranded costs is inherently superior to an administrative determination. Only a market-based determination can reasonably satisfy the known and measurable standard required by the Customer Choice Act.
- Duquesne is entitled to a price cap on generation rates under section 2804(4)(V) of the Customer Choice Act for each year of the Transition Period, subject to early termination of the cap.
- The Duquesne proposal to set customer-specific CTCs annually based on the market price of electricity as determined by the results of a market-based solicitation is efficient, fair to investors and customers, and meets the known and measurable standard.
- The proposed market-based determination of stranded costs as of December 31, 2005 provides a known and measurable methodology to calculate stranded costs on a net present value basis.
- The proposed "true-up" methodology of the final market-based valuation protects customers by ensuring that Duquesne does not over recover its stranded costs and that customers do not "pay twice" for the costs of generation.

Q. Does this conclude your testimony?

A. Yes it does.

R-00974104

Duquesne Statement No. 3-R

Pittsburgh 12-16-97

GSK

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Michael M. Schnitzer

Contents:

Response to Intervenor Testimony Regarding Stranded Cost Calculation and Recovery, and Determination of the CGC for Retail Customers

I. Introduction and Summary

Q. Please state your name.

A. My name is Michael M. Schnitzer

Q. Are you the same Michael Schnitzer who filed direct testimony in this docket on August 1, 1997?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. A number of parties have filed responsive testimony criticizing the Company's proposal for stranded cost quantification, its proposal for stranded cost recovery, as well as the proposed annual CGC determination. The purpose of my rebuttal testimony is fourfold. First, I will describe and catalogue on as consistent a basis as possible the stranded cost position of the Company and certain major parties to illustrate the major sources of difference and contention. Second, I will respond to four of the major stranded cost quantification criticisms put forward by the parties:

- The Company's proposal is deficient in that it does not include a "one-time" quantification of stranded costs as of January 1, 1999;
- The Company's claimed range of stranded generation costs is excessive;
- The Company's proposal will result in over-recovery of stranded costs, unduly burdening customers; and
- The Company's proposal does not include adequate sharing of stranded costs between shareholders and customers.

Third, I will respond to criticisms of the Company's stranded cost recovery proposal, particularly the contention that the Company is not entitled to a price cap under Section 2804(4)(v) of the restructuring statute.

The fourth and final purpose of my testimony is to respond to the criticism that the Company's procedure for determining the CGC on an annual basis using a market auction is flawed.

Q. Could you please summarize your major conclusions?

A. Yes. There are four, one corresponding to each of the purposes of my testimony.

Conclusion 1: Intervenor's Stranded Costs Estimates and Disallowance Proposals

Q. What is your conclusion with respect to the relative stranded cost positions of the Company and the parties?

A. While the Company believes that generation stranded costs should be determined through market mechanisms rather than by debating experts, its best estimate today of stranded costs is $1,916 million as of January 1, 1999, including $374 million in regulatory assets. As shown in the table below, other parties' stranded cost figures are from $139 to $658 million lower than the Company's figure -- $461 million lower in the case of the Industrials, $658 million lower for the OCA, and at least $139 million lower for the OTS (staff has endorsed the Company's proposed future market valuation of generation assets, but has excluded Phillips and Brunot Island from stranded cost recovery and has proposed a lower level of decommissioning stranded costs).

	Duquesne	OCA	OTS	Industrials
Stranded Costs	$1,916 million	$1,258 million	N/A	$1,455 million
Difference from Duquesne	--	$658 million	At least $139 million	$461 million

The largest source of the significant difference between the Company and the Industrials and the OCA is divergent views on generation value and hence on generation stranded costs. There is also a sizable difference between the Company and the Industrials concerning the amount of stranded regulatory assets. In addition to these significant differences concerning the magnitude of stranded costs, there is a further significant difference between the Company and both the OCA and Industrials concerning the amount of stranded costs properly recoverable from customers. The Company proposes that it have an opportunity, but not a guarantee of fully recovering its stranded costs. The OCA and the Industrials propose "sharing" -- the disallowance of prudently incurred costs -- of $232 million and $460 million, respectively. In fact, shareholder losses would be much greater under both OCA's and DII's rate proposals due to tax-related revenue requirements errors in each of their analyses, as further discussed by Mr. Clayton.

Conclusion 2: Four Criticisms of Company's Proposal

Q. What is your conclusion with respect to the four criticisms of the Company's stranded cost quantification proposal you described above?

A. My overall conclusion is that none of these four types of criticism are valid. Thus, as modified, the Company's proposal to value generation through divestiture, at the Commission's direction, should be approved. Specifically:

- The Company's reliance on a future market-based stranded cost evaluation – rather than an administrative determination today – is a strength, not a weakness, as recognized by the Office of Trial Staff. Almost all parties agree that any administratively determined long term market price forecast is nearly certain to be wrong, and thus the one time administrative approach requires both customers and shareholders to make a risky and unnecessary "bet". If the forecast turns out to be too low, customers are harmed; if the forecast is too high, shareholders are harmed. The difference of opinion over market prices and generation value among witnesses in this proceeding serves only to underscore the futility of making a one-time determination of known and measurable stranded costs using administrative techniques. The Company's market based proposal for stranded cost determination, modified to include full divestiture at the Commission's direction, is superior to one-time administrative approaches and should be adopted. However, should the Commission reject this proposal in favor of a one time administrative determination, the Company has put forward adequate evidence to support a stranded cost determination of $1,916 million as of 1 January 1999.
- The claims that the Company has overestimated the likely range of generation stranded costs are not valid. The OCA has overestimated generation market value – and hence underestimated generation stranded costs – by relying on a flawed

analysis of unit shutdown savings and on a speculative assessment of life extension benefits 30 plus years into the future. DII has overestimated generation market value by relying on an inflated forecast of near term capacity prices; a forecast that is at odds both with available market evidence and the OCA's near term price forecast. While Duquesne's projections are reasonable and supportable, this whole debate between dueling experts would be mooted by approval of the Company's market valuation proposal which includes, at the Commission's option, full divestiture.

- Duquesne's proposal will not result in over-recovery of its stranded costs due to the market valuation in 2003 (or earlier) and the ROE spillover provision in the interim. While the market valuation is conveniently ignored by many who accuse the Company of over recovery, this provision does protect customers by ensuring that Duquesne cannot over recover, and thus that customers will not have to "pay twice". As mentioned above, the Company has modified its market valuation proposal and is willing, at the Commission's direction, to auction its generating plants to establish their value. In view of the fact that all parties agree that valuation through divestiture is superior to administrative valuation, the Company cannot legitimately be accused of attempting to over recover -- in fact, it is the one time administrative approach proposed by OCA and the Industrials that creates an over recovery risk.
- The OCA, Industrial, and Environmentalist proposals to disallow recovery of stranded costs are arbitrary and unjustified. They represent the denial of a reasonable opportunity to earn a fair return on prudently incurred, fully mitigated

costs and thus impose asymmetric risks on shareholders for which they have not previously been compensated. These proposals would also have a significant adverse impact on Duquesne's financial performance. Approving such an uncompensated wealth transfer with resulting financial impairment would violate the public policy standards articulated in the Pennsylvania restructuring statute and Duquesne v. Barasch and would be poor public policy. These sharing proposals should be denied. The Company's proposal to recover all of its stranded costs from customers in a competitively neutral, economically efficient manner should be approved.

Conclusion 3: Section 2804(4)(v) Showing by Company

Q. What is your conclusion with respect to the Company's stranded cost recovery proposal?

A. Contrary to the contention of the OCA and HSS, the Company is entitled to a rate cap under Section 2804(4)(v). The Company's analysis demonstrates that it has substantial stranded costs, and this conclusion is corroborated by the OCA and the Industrials -- both estimate stranded costs (before sharing) in excess of $1.2 billion. The possibility of "negative" stranded costs" in 2005 (in the Company's High ceiling price case only) does not disqualify Duquesne from reliance on Section 2804(4)(v); it only raises the issue of the necessary duration of the rate cap. Even under the Company's High ceiling price case, the Company is entitled to the rate cap through the end of 2003 and partway through 2004. Accepting, for arguments sake, all of OCA's assumptions except for its sharing proposal, the Company is entitled to the rate cap through the end of 2003 and partway into 2004, and under the Industrials'

assumptions (except for sharing), the Company is entitled to the rate cap through 2005. Thus, while the Company does not agree that the OCA and Industrial analyses are correct, their testimony does corroborate the Company's position on the likely duration of the rate cap and the proper timing of the market valuation. The proposed market valuation in 2003, together with the trigger provisions for accelerating the market valuation, ensure that the rate cap will be of appropriate duration. The Company's stranded cost recovery proposal should be approved.

Conclusion 4: CGC Determination Through an Annual Auction

Q. What is your conclusion concerning the Company's proposed annual CGC determination?

A. The Company's proposal to determine the CGC on an annual basis is not flawed. In fact, it is necessary to provide an opportunity for fair competition as well as to provide the Company with a reasonable opportunity for stranded cost recovery. This is true because of the statutory provision which gives customers a valuable option – the right, but not the obligation to take service at the rate cap level during the pendency of the transition period, and to return to service at the rate cap level after they have switched to another supplier. The existence of this option requires that the CGC be set on an annual basis using current market prices, otherwise customers will be held hostage to rate cap service if the CGC is too low, and will avoid stranded cost responsibility if the CGC is too high. None of the criticisms of the Company's proposal acknowledge this essential linkage between the rate cap option and the CGC determination.

The criticisms of the Company's proposal to determine the annual CGC by using an RFP are also unfounded. The RFP does not understate the value of power, and any additional credits for retail marketing expense would distort competition and jeopardize stranded cost recovery.

II. Summary of Stranded Cost Positions

Q. Please summarize the major differences between Duquesne and the opposing parties on the magnitude of recoverable stranded costs.

A. Let me answer that in two pieces, starting with differences in the magnitude of stranded costs, and then addressing the different positions on the recoverability of those costs from customers.

Q. How significant are the differences between Duquesne and the opposing parties with respect to the magnitude of stranded costs?

A. There are significant differences as shown in the table below. The largest difference between Duquesne and opposing parties presenting comprehensive stranded cost proposals[1] is in the area of owned-generation stranded costs.

[1] Pennsylvania Office of Consumer Advocate, Office of Trial Staff and Duquesne Industrial Intervenors.

	Duquesne	OCA	OTS	Industrials
Regulatory Assets	$374 million	$331 million	$371 million	$283 million
Owned-Generation Stranded Costs	$1,542 million	$927 million	N/A[2]	$1,172 million
TOTAL	$1,916 million	$1,258 million	N/A	$1,455 million

Regulatory Assets

Q. What are the sources of the above differences in quantified stranded costs as of December 31, 1998 that result from regulatory assets?

A. Duquesne's claim for regulatory assets has largely been accepted by the main intervenors. As detailed in Mr. Clayton's rebuttal testimony and Exhibit DJC-10, once the accounting for taxes and the Beaver Valley II lease are presented on a consistent basis, the OTS is proposing only a minor adjustment of $4 million to the Company claim. The OCA proposes a reduction of $44 million resulting from deferred coal and caretaker costs, and pre-accrued nuclear outage costs. The Duquesne Industrial Intervenors ("DII") are proposing additional adjustments to unamortized debt costs, deferred employee costs and transition costs. These result in total proposed reductions to regulatory assets in the amount of $92 million.

Owned-Generation Stranded Costs

Q. What differences exist with regard to owned-generation stranded costs?

[2] The Office of Trial Staff has not prepared a separate analysis of Duquesne's owned-generation stranded costs. See the testimony of ITS witness Mtero 19:4-13.

A. There are four main elements of the stranded cost calculation for owned-generation reflected in the table below.

	Duquesne	OCA	OTS	Industrials
Net Book Value	$1,237 million	$1,275 million	$1,139 million	$1,257 million
PV of Decommissioning	$124 million	$44 million	$45 million	$43 million
PV of Costs Independent of Operation	$208 million	0	N/A	0
(less) Market Value	($27 million)	($392 million)	N/A	($128 million)
Stranded Plant	$1,542 million	$927 million	N/A	$1,172 million

The net book value of generating plant reflects the unrecovered sunk costs of Duquesne's generation at December 31, 1998. The present value of decommissioning expense reflects the projected future cost of retiring Duquesne's nuclear and fossil units. The costs independent of operation reflects costs at those units showing a negative margin under Mr. Clayton's NPV analysis that will be incurred whether or not that particular generating unit is operated. The estimated market value reflects the present value of the projected future worth of Duquesne's generation valued at market prices for capacity and energy.

Net Book Value

Q. What are the main differences regarding net book value between Duquesne and the intervenors?

A. As detailed in Mr. Clayton's rebuttal testimony and Exhibit DJC-10, Duquesne's net book value number includes the unrecovered cost of cold reserved units, certain M&S and fuel-related sunk costs, and the present value of the Beaver Valley II lease.

Q. How have the intervenor witnesses valued Duquesne's book value?

A. When restated on a consistent basis, the OCA and the DII have also included the unrecovered costs of Duquesne's cold reserved plants and the present value of the Beaver Value II lease in their estimates of total net book value. In addition, as detailed in Exhibit DJC-10, these parties have included a cost of $62 million for working capital. The OTS did not include the cold reserved plants or working capital in its net book value number.

Decommissioning Expense

Q. How have Duquesne and the intervenors dealt with decommissioning expense?

A. Duquesne has included as a future cost (or alternatively, as an offset to future market value) the cost of retiring Duquesne's nuclear and fossil plants of $124 million. The OCA, OTS and the DII have all included present value costs of $43-$45 million for nuclear decommissioning in their estimates.

Costs Independent of Operation

Q. What is the $208 million cost of generation independent of operation?

A. Duquesne's one-time January 1, 1999 administrative valuation shows that under the low market ceiling price scenario Perry, Elrama and Cheswick have negative operating margins and therefore no market value. However, there are operating costs that are unavoidable and will be incurred regardless of whether these units operate such as property taxes and allocated A&G. These costs have not been reflected in

Mr. Clayton's margin analysis which sets the market value of a plant to zero if the present value of the future margin stream is negative, and hence the market value of the Company's generation could be overstated. Mr. Clayton's rebuttal testimony sponsors a preliminary analysis of these units under the spot prices from the solicitation through 2005 and the Low ceiling market price forecast thereafter, and the avoidable operating costs associated with this plants. Based on this analysis, he concludes that Perry and Cheswick are economic to operate on a "to go " basis, and that Elrama is a potential shutdown candidate[3]. His analysis also shows that assumption of a zero value for plants with a negative margin fails to account for $208 million in costs which are not avoidable, and hence represent sunk costs. These unavoidable costs must be included as a stranded cost in the Company's January 1, 1999 valuation.

Market Value

Q. On the issue of market value, what differences exist between the parties?

[3] As detailed in Mr. Karl's rebuttal testimony, the Elrama facility has additional value as a transmission support facility when the Duquesne system is in a "first contingency" status. The cost of less expensive overall solutions to the combined Elrama/transmission constraints problem will require a more detailed analysis, including an option value analysis. Mr. Marshall's rebuttal testimony details the Company's commitment to undertake such a study in 1998 and submit it to the Commission for approval.

A. When adjusted for its treatment of the Beaver Valley II lease expense, the DII estimate of Duquesne's generation market value is $128 million[4]. The OCA estimate of $392 million reflects estimates of added value for temporary shutdowns, life extensions and productivity gains, as discussed in more detail below. As noted earlier, the OTS did not make an explicit calculation of the market value of Duquesne's generation at December 31, 1998, expressing instead a preference for the final 2003 valuation proposed by Duquesne[5]. Duquesne's market value estimate ranges from $27 million in the Low market ceiling case to $159 million in the Delayed entry case, to $278 million in the High market ceiling case. The specific causes of these significant differences in generation market value are discussed at length later in the testimony.

Recoverability

Q. Let's turn now to the second issue, the extent to which stranded costs, of whatever magnitude, are recoverable from customers. Please summarize the proposals of the intervenors regarding the "sharing" of stranded costs by Duquesne.

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[4] The filed DII testimony indicated a value of negative $17 million for Duquesne's generation, but includes the Beaver Valley II lease payments in the A & G expense. Removing these expenses from A&G and treating the lease on a consistent basis with the approach taken by Duquesne and OCA results in an increase in the market value of generation to positive $128 million.

[5] At p. 19 of his direct testimony, OTS witness Metro recommends – if the Commission determines the Duquesne approach is not permitted under the Act – that, as an alternative, Duquesne be permitted to file a CTC based on Duquesne's stranded costs as of January 1, 1999 using "stranded costs quantified but not claimed in the Company's filing."

A. Both the DII and the OCA advance different sharing proposals based on some level of disallowance of return on the owned-generation stranded costs. In the case of the Industrial Intervenors, witness Baron recommends that the Company be allowed no equity return on its own-generation stranded costs over the seven year amortization period. According to Mr. Baron, the economic effect of this proposal is equivalent to a $232 million stranded cost disallowance.

Q. How does the OCA proposal differ?

A. Mr. Kahal's sharing proposal is to allow customers to pay for amortization of owned-generation stranded costs over seven years with no return allowed for common equity, preferred or debt.

Q. What is the effect of OCA's "sharing" proposal?

A. Mr. Clayton details the impact of the OCA proposal in Exhibit DJC-12 to his rebuttal testimony. He has adopted the approach used by the DII witness to calculate the net present value difference between revenue requirements calculated using a full return and using the disallowance proposed by the OCA. The NPV impact of the OCA "sharing" proposal is $460 million. The effect of the "sharing" proposed by the Industrials and the OCA is to disallow a significant amount of prudent investment currently in rates.

III. Stranded Cost Quantification and Recovery Criticisms Are Invalid

Market Based Stranded Cost Valuation Preferred

Q. Let's start with the complaint that the Company's proposal is deficient because it does not include a "one time" administrative quantification of stranded costs as of January 1, 1999. Which parties raise this issue?

A. The witnesses for the OCA and the Industrials make this point.

Q. there an advantage to making a one time administrative stranded cost determination?

A. No. In fact there are significant disadvantages to a one time administrative determination in comparison to a market-based determination of stranded costs. The most significant problem is that an administrative determination is almost certain to be wrong, largely due to our inability to accurately forecast market prices in the manner proposed by the OCA and the Industrials. There is a long history of such "avoided cost" price forecasts in Pennsylvania and other parts of the country, and the experience is quite consistent: actual market prices turn out to be far different, and usually lower, than the administratively determined forecast (see Exhibit MMS-6 for descriptions of three case studies). In short, these forecasts have proven to be very inaccurate. For this reason, the Company prefers a market based stranded cost determination, and has proposed such an approach rather than a one time administrative determination.

Q. Do the other parties insist that an administrative determination is as good as or better than a market determination.

A. No, they do not. In fact, many parties agree that at least one type of market valuation -- divestiture -- is superior to a one time administrative valuation. Mr. Marshall's rebuttal testimony describes the positions of the intervenors with more specificity.

Q. Well, if the parties agree that some form of market valuation is preferable to a one time administrative determination, what is the problem? Why hasn't the Company's proposal for market valuation of stranded costs been endorsed by parties other than the OTS?

A. There are two reasons. First, some parties do not accept the appraisal process proposed by the Company to be an adequate market valuation. While the Company believes that the process it proposed, relying on market data rather than computer simulations, is a decided improvement over the administrative determination proposed by the OCA and the Industrials, it has modified its original proposal to utilize divestiture for valuation purposes rather than the market appraisal process, at the Commission's option. This modification leaves to the Commission the decision as to whether an auction of the Company's generation, or another market valuation technique should be utilized. This should satisfy the expressed concerns with the appraisal process.

Q. You mentioned there were two reasons why certain parties have not endorsed the Company's market valuation proposal. What is the second reason?

A. The second reason has to do with timing. The Industrials, in particular, argue that divestiture is preferred to administrative valuation only if it can be completed before the January 1, 1999 access date. If divestiture would not take place until after this

date, as in the Company's proposal, Industrials argue that administrative valuation would be preferred.

Q. Why do the Industrials take this position?

A. While they do not dispute that valuation through divestiture is superior to administrative valuation, they claim that the certainty of the stranded cost and CTC amounts prior to access is more important than the accuracy of the valuation. .

Q. Do you agree?

A. No, I do not, for two reasons. First, even assuming for the moment that the certainty vs. accuracy tradeoff is real, the potential for error introduced by administrative valuation, and the attendant risk to both customers and shareholders is just too significant to overlook, or ignore. If the administrative valuation errs on the low side, customers are harmed because stranded costs are overstated. If the administrative valuation errs on the high side, shareholders are harmed because stranded costs are understated. And in both cases, the error can be significant. Simply stated, in the face of the horrible historical performance of administratively determined market prices, sacrificing the accuracy of market valuation to the expedient of CTC certainty is a poor trade.

The second and perhaps more important reason is that the choice framed by Mr. Baron between certainty and accuracy is itself flawed and illusory -- pre-1999 valuation, either through market or administrative mechanisms, will not result in CTC certainty. The reason for this is the customer option under the statute to take service at the rate cap level throughout the transition period. So long as customers have this option, their choice between rate cap service and service from another supplier will be

influenced by the relationship between the CGC and the market price. If the CGC is less than the market price, there will be an uneconomic incentive to take rate cap service; conversely, if the CGC is greater than the market price, there will be an uneconomic incentive to switch to another supplier. Only by setting the CGC equal to the current market price will the choice between rate cap service and other suppliers be competitively neutral and fair to all parties. This is precisely the approach adopted in California during the pendency of the price cap alternative. The CGC will be based on the actual average power exchange price.

The implication of this is that the CGC cannot be predetermined so long as customers have the option of rate cap service. And if the CGC cannot be predetermined, then the certainty benefits that Mr.Baron alleges are associated with pre-1999 valuation are illusory. Put another way, achieving the certainty benefits in the manner advocated by Mr. Baron requires:

- An administrative valuation which exposes both customers and shareholders to significant valuation risk; and
- A predetermined CGC schedule that will almost certainly distort customer choices between rate cap and competitive supply.

The costs of such an approach outweigh any potential benefits. The OTS and Industrial proposals for one time administrative valuation of the Company's generation should be rejected. The Company's modified valuation proposal should be approved.

Generation Stranded Costs Not Over Estimated

Q. Which parties present alternate views of the value of the Company's generating assets?

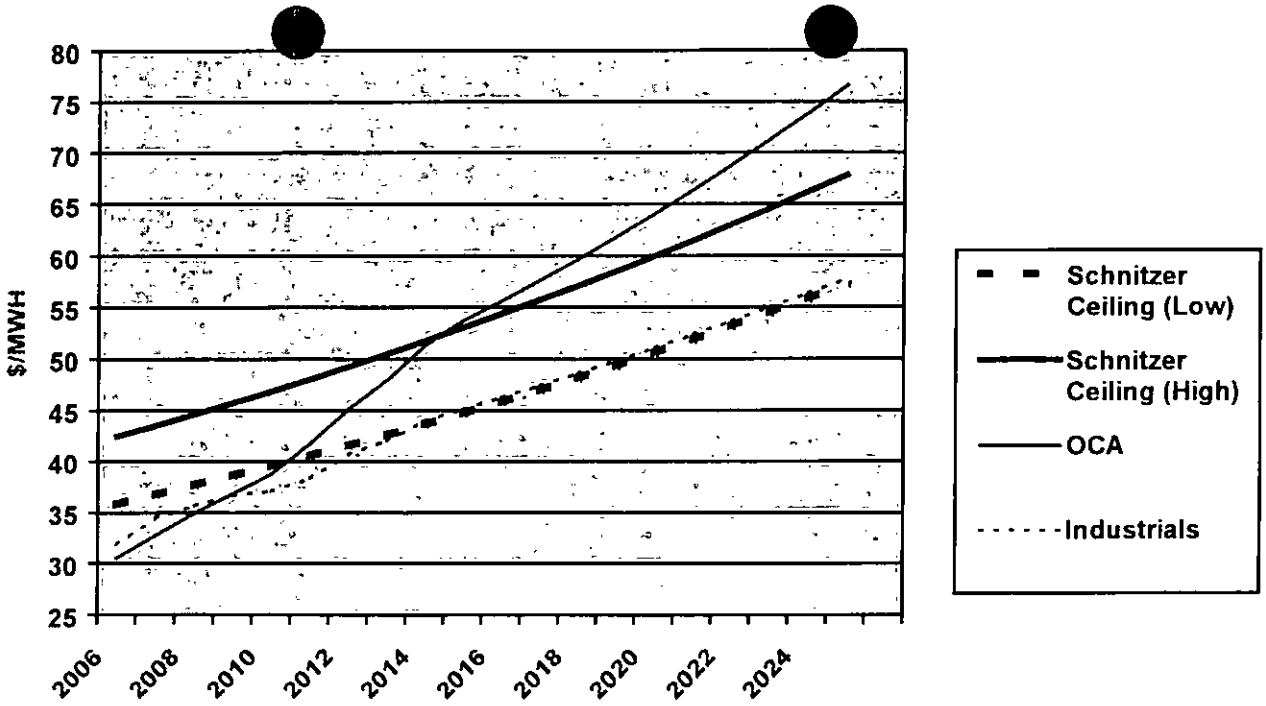
A. The OCA and the Industrials each present estimates of generation value which are significantly higher than the Company estimates as shown in the table below.

	Duquesne	OCA	Industrials
Generation Operating Value	($181 million)	$392 million	$128 million
Difference from Duquesne	--	$573 million	$309 million

Q. The OCA and the Industrials have been quite critical of your ceiling market price estimates on which the Company relied to estimate generation market value. I take it that your ceiling price range is much lower than the market price forecasts of OCA and the Industrials?

A. Actually, and surprisingly given their rhetoric, the answer is no. The figure below illustrates my ceiling market price range from 2006 on, together with the market price assumptions relied on by OCA and the Industrials.

As the figure shows, through the year 2010 both parties forecast market prices lower than the low end of my ceiling price range, indeed the Industrial forecast is lower through the year 2013. Over the remaining forecast period, the Industrial forecast lies nearly on top of the low end of my ceiling price range, while the OCA forecast escalates more sharply to a point just above the high end of the range in the year 2015, and diverges further from that point.



Q. On average, how do the OCA and Industrial market price estimates compare to your ceiling price range over the 2006 to 2025 time period?

A. My ceiling market price ranges from $36 per MWh to $43 per MWh in 2006, on a real levelized (that is, escalating at inflation) basis. The comparable number for the OCA is $39 per MWh, and for the Industrials $35 per MWh. Thus, the Industrial market price forecast for 2006 and beyond is actually below the low end of my ceiling price range, while the OCA's figure is well within my range.

Q. Given all of the criticisms of your approach, why isn't there more of a difference between your ceiling price range and the market price forecasts of OCA and the Industrials?

A. While it is true that some of my assumptions, capital cost and heat rate in particular, are lower than those of these other parties, other of my assumptions, notably cost of capital and capital recovery period, are higher. Thus, to some extent the differences in assumptions offset each other. In addition, my ceiling price range assumes that market prices will have risen to the combined cycle new entry level by 2006,

although I acknowledge the possibility that with all the excess baseload generation in ECAR, prices may not in fact rise to that level until after 2006. Industrials and OCA conclude that combined cycle capacity will not be economic under their assumptions until well after 2006, again with the result that the market price estimates are closer together rather than further apart. But underlying the apparent numerical similarity, there are significant differences of opinion over the usefulness of such forecasts.

Q. What do you mean?

A. Both the OCA and the Industrials are willing to rely on these forecasts as the basis of a one time stranded cost valuation, hedging their bet on market prices through their sharing proposals, which would impose significant costs on shareholders. The Company, on the other hand, believes these forecasts are useful only for the purpose of establishing the likely magnitude of stranded costs so as to determine the appropriate timing for the proposed second stage market valuation.

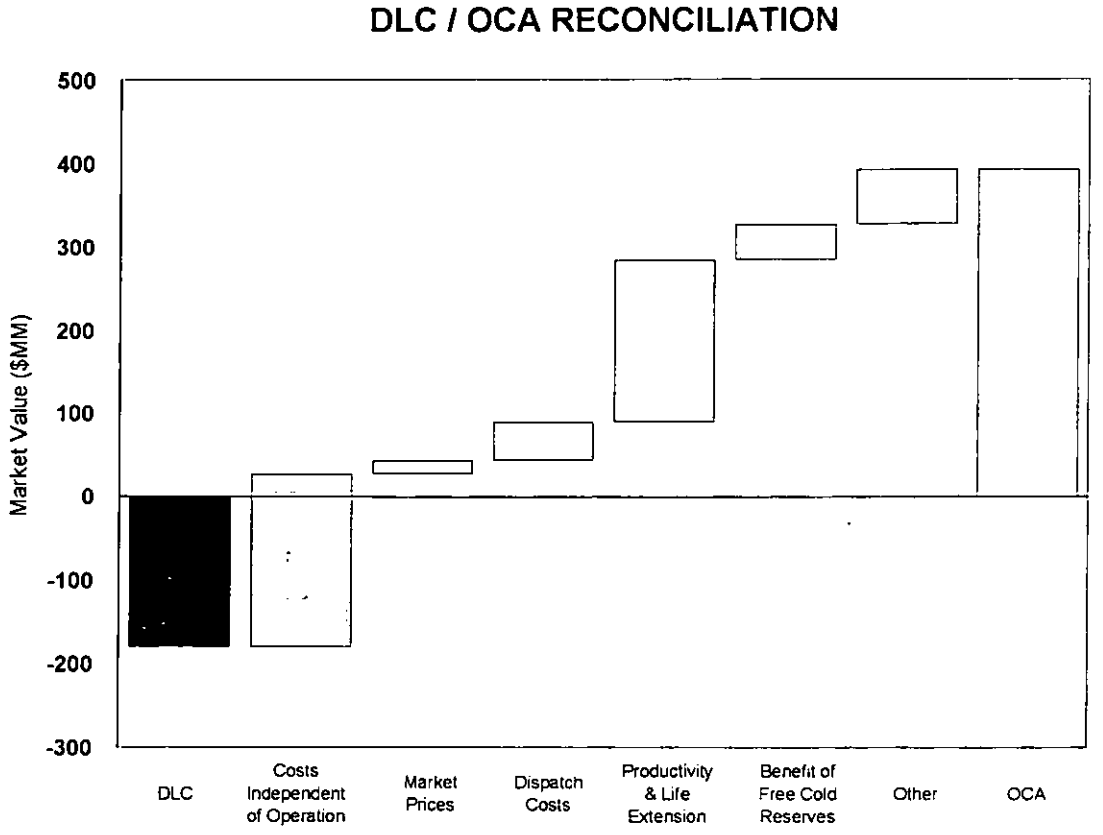
Q. To what do you attribute this difference of opinion?

A. I attribute it to a fundamentally different view of how competitive markets work. The specific criticisms of my approach are very revealing in this regard. The core criticism of the other parties is that I have assumed lower capital costs and higher efficiencies than any combined cycle unit currently operating, or than any unit currently available for construction. The first contention is true, the second arguable, but both miss the point. The critical question that OCA and the Industrials never even bother to ask is: has administrative determination based on current technology cost been an accurate predictor of market prices 10 to 20 years hence? The answer is no. In my experience the administrative approach based on a fixed technology view of

the world has been high nearly every time, and three specific examples are summarized in Exhibit MMS-6. Yet, for instance, OCA has the temerity to value life extensions 29 to 37 years hence based on such a fixed technology forecast. In light of the documented failures of accurately predicting market prices even five years in the future, OCA's position is somewhere between silly and reckless. Technological progress in electricity production is a fact. Gas combined cycle costs have fallen dramatically in nominal dollars over the last several years. Indeed, a review of Gas Turbine World, one of the sources cited by Mr. Falkenberg, indicates that in the just the last year, turnkey cost estimates for some combined cycle technologies have fallen by 17 to 33 percent (even more in real terms), and installed costs are now quoted as low as $318 to $380 per kW. In a similar vein, the Energy Information Administration, citing improved efficiency and lower costs of generation has reduced its forecast of long term electricity prices by 13 percent relative to a similar forecast made only one year ago. Given these trends, given the prospect of new technologies displacing combined cycle, and given the experience of the last 15 years, it is only reasonable to acknowledge the real possibility that future market prices could be lower than the ceiling price range, and lower than the OCA and Industrial forecasts.

Q. Well, if differences in long term market price assumptions are not that significant, why are the Company's estimates of generation value lower than the other parties?

A. The specific reasons vary for each party. Let me start with a discussion of the OCA analysis. The figure below illustrates the major sources of the $573 million difference between the Company's $(181) million estimate of net generation value and OCA's $392 million estimate.



Q. Please explain the $208 million of difference attributable to costs independent of operation.

A. Under Mr. Kahal's cost and market price assumptions, several of Duquesne's generating plants have a negative margin over their remaining lives – that is, the present value of costs exceeds the present value of revenues. For stranded cost quantification purposes, Mr. Kahal does not use this negative margin figure, but instead uses a value of zero. Implicit in his choice to use zero rather than the projected negative margin is the assumption that the operating costs which produce the negative margin are all avoidable if the unit is shut down or placed in cold

reserve. Unfortunately, as Mr. O'Brien, Mr. Duckworth and Mr. Nelson testify, this is not the case. Certain operating costs are not avoidable, and cannot be saved. Mr. Kahal's incorrect assumption that these costs are avoidable causes him to overstate net generation value by over $200 million.

Q. What about the $17 million difference attributable to market prices.

A. The OCA market prices are virtually identical to the prices derived from Duquesne's recent auction through 2002, but escalate more quickly thereafter, and thus are above the low end of the ceiling price range, on average, over the forecast period. But the net effect of these market price differences is only $17 million, as the figure illustrates.

Q. Please explain the difference in value attributable to dispatch costs.

A. The Company and OCA use different assumptions with respect to fuel and variable O&M costs.. The effect of using OCA's assumptions, rather than the Company's, is to increase net generation value by $44 million.

Q. What about the $196 million in the figure above attributable to life extensions and productivity improvement?

A. A more significant source of difference involves life extension and productivity assumptions. The Company believes that future life extension economics are speculative, and will hinge both on future market prices and environmental requirements for coal generation. OCA has assumed that life extension will be economic, particularly at the higher long-term price levels they project. In addition, OCA has assumed further, unspecified improvement in generation productivity above and beyond the Company's projections. As shown above, these speculative life

extension assumptions together with their unspecified productivity improvements increase net generation value by $196 million.

Q. What is the next item, the benefit of free cold reserves?

A. Mr. Kahal's analysis suggests that the Cheswick unit has negative margins on an annual basis until 2006, at which time the annual margin turns positive. For valuation purposes, Mr. Kahal assumes that the Cheswick unit can be placed in reserve for free until 2006, at which point it can be reactivated at no cost. Unfortunately, as Mr. Nelson describes, this is not technically or economically feasible. The "free cold reserve" error causes generation value to be overstated by $42 million.

Q. What is in the "Other" category?

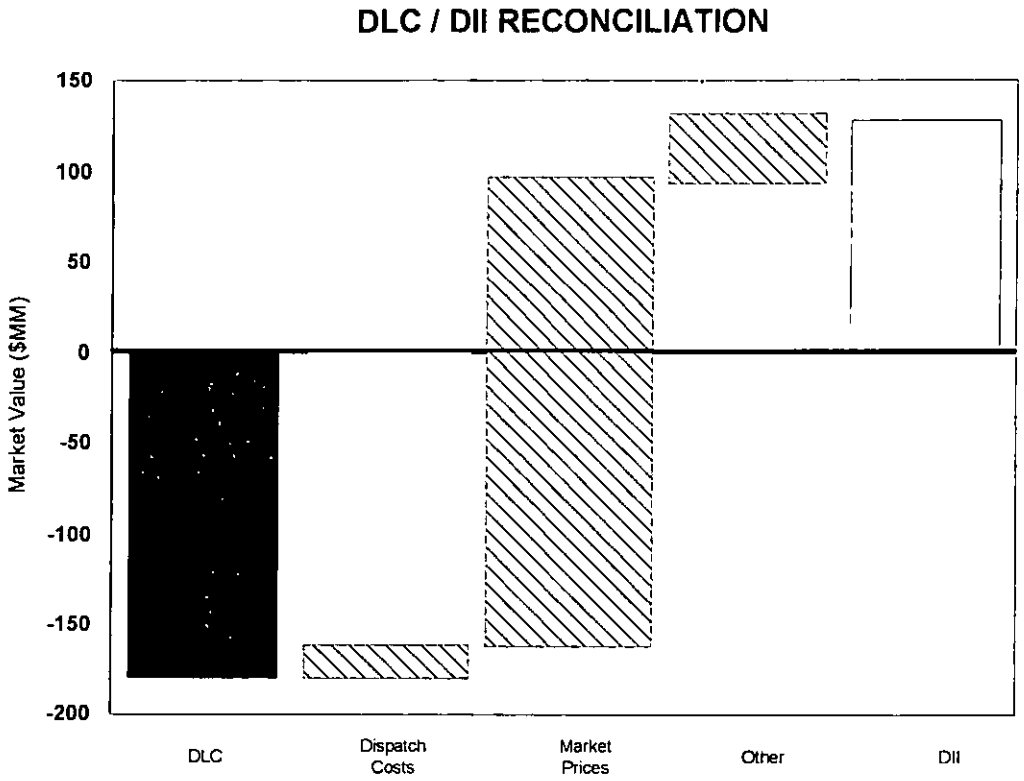
A. There are several other differences in assumptions between OCA and the Company, including inflation and discount rates. As the figure illustrates, these other differences account for $66 million of the difference in net generation value.

Q. What do you conclude from this analysis of differences between the Company and OCA net generation plant valuations?

A. The difference in values of nearly $600 million is clearly a significant difference. Much of it is attributable to errors in the OCA's analysis. The assumption that all costs are immediately avoidable, and that there are no costs independent of operation is just wrong. Likewise the assumption that a unit can be placed in cold reserve for a number of years and then reactivated for free is also incorrect. The life extension benefits are possible, but extremely speculative, and the productivity improvement assumption is unsupported. On balance, the Company's valuation is more reasonable than the OCA valuation.

Q. What about the DII analysis of net generation plant value?

A. The figure below summarizes the major sources of the $309 million difference in net



generation value between the Company and DII. As the figure illustrates, the major source of difference -- $255 million – is market price assumptions. Different fuels price assumptions account for a very small part of the difference, and all other sources account for about $35 million of the difference.

Q. Why is the market price difference so significant? From 2006 on, isn't DII's market price forecast actually a little lower than the Company's?

A. In the long term DII's market price projection is just below the Company's ceiling price range, but during the transition period DII's market price is well above the projection based on RFP results and well above OCA's projection as well.

Q. Why is that?

A. On an energy basis, all the forecasts are quite comparable during the transition period. The difference is entirely attributable to Mr. Falkenberg's capacity price assumption. Based on his reserve margin analysis, he assumes that the market will support a capacity price equal to the economic costs of a new combustion turbine starting in 1999. Neither the results of Duquesne's RFP nor the Company's experience in the market as a purchaser of capacity (as described by Mr. Lahtinen and Mr. Irvin in their direct testimony) are consistent with this assumption, but Mr. Falkenberg is apparently undeterred. With no market evidence to support the DII assumption, and ample market evidence to support the Company's position (plus, in this regard, the analysis of OCA), the Company's net generation value is much more reasonable than DII's.

Q. What about HSS's contention that there are no generation stranded costs?

A. Mr. Clayton discusses Mr. Weisenmiller's valuation contentions in more detail, but I have two observations. First, to the extent Mr. Weisenmiller is relying on the Fort Martin transaction to support his valuation, his valuation should be rejected. Relying on a single, old transaction to value all of Duquesne's generating assets is simply not credible. Mr. Weisenmiller offers no evidence that similar transactions could be achieved today, or that such a transaction can reasonably be generalized to all of the Company's generation. Second, while he references selected values from past assessments of the market value of the Company's assets performed by Duquesne and others, he offers no evidence that the market price assumptions underlying the valuations he cites are in fact reflective of current power markets. The Company's

RFP results indicate that they are not. To the extent his valuation relies on these selective citations, it should be rejected.

No Opportunity for Over Recovery

Q. Opposing parties have made the claim that Duquesne's rate cap and market valuation proposal may result in over recovery of stranded costs. Why do they believe this will be the case?

A. For the most part, this concern stems from a belief that the Company has overestimated its stranded costs, and that allowing recovery of the amount requested would translate to over recovery. There are also secondary issues concerning the ROE spillover mechanism; particularly whether the Company could game that mechanism to achieve over recovery, or would have insufficient incentives to mitigate stranded costs to the detriment of customers.

Q. How do you respond?

A. Duquesne's proposal will not result in over recovery of its stranded costs because the proposal is premised on a market valuation of its generation assets, not on a one time administrative valuation. If the market valuation indicates that stranded costs are lower than what the Company now believes, and maintaining the rate cap through the end of 2005 is not necessary, then the recovery period can be shortened. That is why the Company is proposing that the valuation be completed in 2003 so that any required adjustments to the rate cap could be made in 2004 and 2005. As shown in Mr. Clayton's Exhibit DJC-21 (Revised Exhibit DJC-3, p.2) over 600 million of the Company's minimum amortization commitment is not funded until 2004 and 2005, so

even if stranded costs turn out to be significantly lower than the Company believes likely, no over recovery will have taken place prior to 2004.

Q. But what if market prices turn out to be much higher than the Company's current projections – couldn't a 2003 valuation be "too late"?

A. That possibility certainly exists as a theoretical matter. And rather than debate the probabilities, the Company has instead proposed a market price trigger, described by Mr. Clayton, which would accelerate the market valuation if market prices rise more quickly than now anticipated. As well, Mr. Clayton describes a second trigger for early valuation in the event the Company is able to fund accelerated amortization more quickly than it now forecasts, as a consequence of higher load growth or lower costs, for instance. Thus the Company's proposal provides for acceleration of the market valuation in circumstances where 2003 might be "too late".

Q. What if, despite the Company's best intent, the market valuation indicated that the Company had already over recovered its stranded costs?

A. In that unlikely event, the rate cap would be terminated, and the Company would credit the over recovery back to customers, with interest, according to a Commission approved schedule. The Company would not retain the over recovery.

Q. Could you please summarize why there is no opportunity for over recovery under the Company's proposal?

A. Yes. The Company has proposed a market valuation of stranded costs to ensure there is no opportunity for over recovery. The timing of that valuation, and the triggers for accelerating it, provide adequate protection for customers that the rate cap will not remain in place any longer than necessary. In the unlikely event that, despite these

protections, the rate cap did provide more recovery than required, the rate cap would be terminated and all excess recovery credited back to customers. Thus, under the Company's proposal, in contrast to the one time administrative valuation proposals put forward by the OCA and the Industrials, there is no opportunity for Duquesne to over recover its stranded costs.

Q. What about the criticism that during the price cap period the ROE cap creates an opportunity for excess earnings, which effectively represent over recovery?

A. As discussed by Mr. Clayton, the Company has modified its proposal to eliminate the 50 basis point band above the allowed return on equity. Therefore, all earnings above an 11.5 percent return would be used to fund amortization – there is no opportunity for the Company to earn a return in excess of the Commission authorized rate.

Q. What about the related criticism that the Company does not have adequate incentives to minimize stranded costs under the ROE spillover, and that either gaming or inefficiency will cause customers to pay more for stranded cost recovery than they should?

A. These criticisms are incorrect. The Company has strong incentives to mitigate stranded costs and to operate efficiently during the rate cap period.

Q. What are these incentives?

A. There are two. The first stems from the minimum amortization commitment, a complementary feature of the Company's plan. Simply stated, the Company has committed to fund at least $1.7 Billion of accelerated amortization during the rate cap period independent of its effect on earnings. That means that the Company is effectively at risk for creating enough operating income to both fund the amortization

commitment and to achieve the Commission authorized return. If the Company is not able to generate the required level of operating income over the rate cap period, for whatever reason, then its earnings will suffer. Given that the amortization commitment already reflects aggressive operating performance assumptions (increased fossil output and significant nuclear performance improvement at Perry, for instance), this is a significant incentive to maximize operating income through any means available, including stranded cost mitigation specifically and improved operating efficiency more generally. I should also note that no party has presented an analysis suggesting that this minimum commitment is inadequate or not sufficiently aggressive under the Company's return on equity assumptions.

Q. What is the second incentive to mitigate under the rate cap?

A. The second incentive is that it is in the Company's interest to minimize any remaining unrecovered stranded costs at the end of the transition period, to eliminate them entirely if at all possible, and to generally keep the stranded cost recovery period as short as possible. The best way to do that during the rate cap period is to aggressively mitigate stranded costs, operate as efficiently as possible, and therefore maximize the amount of additional amortization that can be funded through the ROE spillover mechanism.

Q. Why is it in the Company's interest to keep the stranded cost recovery period as short as possible?

A. There are a number of reasons. First, the Company has a strong interest in avoiding the time expense and uncertainty associated with a future proceeding to extend stranded cost recovery beyond 2005. While it believes, as a matter of law, that it is

entitled to such recovery if required, the best outcome from the Company's perspective is that stranded cost recovery be completed prior to the end of 2005. Beyond that, completing stranded cost recovery as soon as possible will allow customers to benefit from lower rates, and it will relieve the Company from its obligation to provide generation service at the rate cap level – both desirable outcomes.

Q. For the skeptics among us, is there any evidence that this is an effective incentive?

A. Yes, there is. Prior to the passage of the restructuring statute, Duquesne was faced with a similar, if weaker set of incentives. There was no defined rate cap process, and no specific schedule for access or stranded cost recovery – but there was a general sense in the Company that reducing potentially strandable costs as quickly as possible was important. With no stronger nor more explicit incentive than this, the Company aggressively pursued cost reductions that allowed it to petition for authorization to accelerate amortization of its nuclear plants, and subsequently entered into the Fort Martin transaction which allowed it to further mitigate stranded cost. In light of its past actions, it is clear that Duquesne is motivated to do everything possible to fully mitigate its stranded costs and to recover them as quickly as possible. It has continued strong incentives to do so under its proposal.

Q. Have any parties offered any constructive proposals to further strengthen the Company's incentives?

A. No, they have not.

Disallowance of Stranded Costs Is Arbitrary, Unjustified and Poor Public Policy

Q. Would you now please address the sharing proposals that have been put forward by several parties?

A. Yes, I will.

Q. Could you please define the term "sharing" as it is used in the context of quantifying stranded costs?

A. Yes. Proponents of sharing advocate that after the magnitude of stranded costs has been determined, a further determination be made as to what portion of these stranded costs is recoverable from customers and what portion is imposed on investors. This latter determination of the allocation of stranded cost responsibility between customers and shareholders is referred to as sharing. A more accurate, if also more blunt, definition of sharing is: the denial of a reasonable opportunity for shareholders to earn a fair return on prudently incurred, fully mitigated costs currently authorized to be included in just and reasonable rates.

Q. What parties advocate "sharing" of stranded costs?

A. At least three parties -- OCA, Industrials, and Environmentalists – advocate sharing of one type or another. HSS may also be an advocate of sharing, as well, but the issue is mooted by its conclusion that the Company has no stranded costs.

Q. Are all the sharing proposals the same?

A. No, they are not. The OCA's sharing proposal is to allow seven year amortization, with no return, of generation stranded investment. As discussed by Mr. Clayton, this proposal translates to a $460 million stranded cost disallowance under OCA assumptions, and a larger disallowance under Company assumptions. The

Industrials' sharing proposal is to allow amortization, with no equity return, of generation stranded investment. This proposal would result in a $232 million disallowance under Industrials' assumptions, and a larger disallowance under Company stranded cost assumptions. In addition, as described by Mr. Clayton, the OCA and the Industrial recovery proposals provide for an additional "sharing" of $42 million and $166 million respectively, due to treatment of deferred taxes. The Environmentalists recommend no more than 60 percent recovery of generation stranded investment. Under Company stranded cost assumption, this proposal would result in a disallowance of at least $766 million.

Q. What is the basis for your conclusion that these sharing proposals are unwarranted and are poor public policy?

A. There are two reasons. First, these sharing proposals are arbitrary and are not consistent with the public policy standards for stranded cost recovery set out in the Pennsylvania statute. Second, these sharing proposals are inconsistent with the public policy standards articulated in Duquesne v. Barasch.

Q. Let's start with the first reason. Why are these sharing proposals arbitrary and inconsistent with the public policy standards in the statute?

A. The statute describes a number of factors relevant to the determination of generation stranded cost recovery [See Sections 2808(c)(4) and 2808(c)(5)]. They all deal fundamentally with the issue of mitigation, both historically prior to the passage of the statute and prospectively during the transition period. By their nature, these statutory considerations are company and fact specific, rather than generic. Despite this statutory requirement, the sharing proposals put forward by the parties are not

based on any assessment of the Company's mitigation efforts, either historically or prospectively. In fact, the sharing proposals do not appear to be company-specific at all. Rather they are proposed to be applicable to any company with generation stranded cost, regardless of the circumstances.

Q. How do you know these proposals are not based on an assessment of Duquesne's mitigation activities?

A. Each party has offered a justification of its sharing proposal. None of them mention mitigation. Mr. Kahal for the OCA states "Given the 'just and reasonable' standard and the fact that virtually all of the owned-generation stranded cost would normally be considered 'economic excess capacity,' a sharing mechanism is clearly appropriate."[Kahal; p. 41:22-25] Similarly, Mr. Baron on behalf of the Industrials provides his justification for the sharing proposal:

> Q: Based on your understanding of the provisions of the Competition Act and the Commission's application of that Act in the PECO QRO proceeding, does the Commission have a responsibility to apply the just and reasonable standard in the determination of the amount of generation-related stranded costs that may be recovered from ratepayers?
>
> A: Yes. I believe that some adjustment or discount from the total calculated level of stranded generation costs (if they are found to be a positive value) should be made prior to the calculation of the recovery of such costs through a CTC. The methodology that I am recommending in this proceeding is a reasonable approach to making such a stranded generation cost adjustment to

arrive at a just and reasonable level to recover from its customers. [Baron; p. 18:10-21]

In fact, Mr. Baron is not familiar with, and thus presumably did not consider any specific standards for generation stranded cost recovery specified in the statute:

> Q: Is it your understanding whether the statute sets forth any standards for the Commission to consider?
>
> A: I am not aware of specific standards in that regard. Rather the statute, and I've cited some sections in my testimony, discusses the general obligation of the Commission to determine a just and reasonable level of stranded cost recovery. [Baron; p. 52:20 to p. 53:3]

Finally, Mr. Schoengold offers the justification for the Environmentalist sharing proposal. He, too, is silent on the issue of mitigation. "The stockholders have already received a return on their investments in the generating assets, even on that investment which has turned out to be valueless. It is necessary to take this into consideration when determining how to share the economic loss." [Schoengold; p. 20:7-10] And further: "I am recommending that the Commission allow for recovery of no more than 60% of the level of stranded generating assets which it determines are appropriately recoverable. This is a reasonable level which allows stockholders a reasonable authorized return on investment." [Schoengold; p. 23:8-11]

Q. I understand that these proposals are not based on an assessment of the Company's mitigation efforts, but could you comment on the alternative justifications offered by the parties?

A. Yes. OCA and the Industrials appeal to the just and reasonable standard as permitting or requiring sharing of the type they propose. But the just and reasonable standard is not a new standard – it applies to Duquesne today. I fail to see how Duquesne's rates can be just and reasonable today based on prudently incurred costs and magically be unjust and unreasonable the next day based on the same prudently incurred costs. The Environmentalist's justification for sharing is no better. Mr. Schoengold invents a new concept of IRR realized to date to effectively deny any further equity return on generation stranded investment. There is no theoretical basis for his proposal; it is an arbitrary method for determining stranded cost recovery on the basis of average asset vintage, rather than the mitigation considerations specified in the statute.

Q. What about the bases for the particular sharing calculations proposed: no return, no equity return, and no more than 60 percent recovery, respectively?

A. They are all arbitrary and unsupported. Neither Mr. Kahal nor Mr. Baron offers any explanation as to why their particular return penalty is more appropriate than a more or less severe penalty. Neither recommendation is based on an assessment of Duquesne's mitigation efforts, neither is even specific to the Company's circumstances in any way. These are simply arbitrary blunt instruments designed to shift costs from customers to investors. Mr. Schoengold's proposal is no better – his particular recommendation stems from an accident of history, the average vintage of Duquesne's generation. A younger, less depreciated asset mix would deserve a lower ROE under his theory, an older more depreciated asset mix would be entitled to a higher ROE. There is no basis in the statute or in logic for such an arbitrary proposal.

Q. In your earlier summary, you mentioned additional policy standards by which to evaluate these sharing proposals, the policy standards articulated in Duquesne v. Barasch (*Duquesne*). What are those standards, and why do these sharing proposals fail to meet them?

A. I will preface my response by noting that I am not a lawyer and I am not offering a legal opinion. But, from a non-lawyer's perspective, the *Duquesne* opinion includes two useful policy standards. In dealing with the issue of whether the consequences of unsuccessful investments could be imposed on investors, the notion that prudence was by itself determinative of the issue was rejected. But *Duquesne* did continue to recognize the "end results test" of a company's financial performance as a relevant policy standard. In addition, *Duquesne* put forward an additional policy standard that opportunistic switching by regulators from one set of rate setting rules to another is not appropriate. It also suggests that the question of distinguishing opportunistic switching from permissible cost recovery rules which appropriately impose losses on shareholders hinges on whether there is a match between the losses imposed on shareholders and the prior level of risk compensation they received through the rate of return on equity. Thus, to meet these policy standards, a sharing proposal must produce financial performance which passes the "end results" test, and show evidence of prior compensation to distinguish the proposal from opportunistic switching. None of the sharing proposals satisfy either of these policy standards.

Q. How do you know that none of these proposals pass the end results test?

A. None of the proposing parties considered, let alone demonstrated that the end result of their proposal is reasonable in terms of the financial consequences to the Company.

Mr. Clayton does address this issue, however. His testimony summarizes the financial consequences of the OCA proposal and the DII proposal on the Company. His analysis indicates that the end result of either proposal is significant deterioration of the Company's financial health. He further concludes that applying Mr. Schoengold's proposal to the Company stranded cost assumptions would have similar consequences.

A. Have any of the parties proposing sharing made a showing of prior compensation?

A. No, they have not, nor have they acknowledged that the question of prior compensation is even relevant. Mr. Kahal states that evidence of prior compensation is not the basis of his sharing recommendation:

> Q: Are you contending that Duquesne's shareholders have been compensated for this disallowance or adjustment?
>
> A: They may have been in the sense that during some period of time Duquesne shareholders may have earned returns that exceeded the cost of capital, but that's not the basis of what I'm doing. [Kahal Deposition; p. 82:13-20]

Mr. Baron states that he doesn't know whether shareholders have been compensated for the risk of a disallowance:

> Q: Do you believe that Duquesne's shareholders have been compensated for the risk of such a disallowance that you propose?
>
> A: I haven't made that determination. I simply don't know at this point in time. [Baron Deposition; p. 55:4-8]

And finally, Mr. Schoengold states that he doesn't know whether there has been compensation, but that the presence or absence of compensation was not relevant to his analysis:

> Q: Is it fair to say that your analysis or your calculations assume that the shareholders have not already been compensated for the stranded cost disallowance or sharing that you propose?
>
> A: That the shareholders have not been compensated for the stranded cost disallowance that I proposed?
>
> Q: That's correct.
>
> A: I haven't followed the performance of Duquesne stock, so I don't know just what they may or may not have been compensated for. But, I didn't make any assumptions in my analysis as to whether or not they had been compensated for that potential disallowance. [Schoengold Deposition; p. 42:12-22; p. 43:1-4]

Thus, none of these sharing proposals are based on any evidence of prior compensation.

Q. I understand that none of the parties have demonstrated that shareholders have been compensated for the risk of the losses they now propose to impose on them. Do you think it is likely that shareholders have been compensated to assume these risks?

A. No, I do not.

Q. Why not?

A. For shareholders to have been compensated in the manner envisioned in *Duquesne*, the PUC would have had to adjust the risk premium element of the rate of return to

account for the risk of prudent, but economically unsuccessful investments. To do so would have required some sort of mechanism to quantify the magnitude of this risk, to translate it into an ROE premium, and to add it to the expected ROE determined through normal means. The problem is that this is easier said than done. There were no formal techniques used, to my knowledge, to quantify this type or asymmetric risk in Pennsylvania. Nor would this risk premium have been picked up automatically through some other estimation technique. As Kolbe, Tye and Myers conclude: "However, unlike debt, *the 'observed rate of return for equity is its expected rate of return, not the equivalent of a promised rate of return.*" (Kolbe, Tye, and Myers; Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries; pp.42-43; emphasis in original) The ROE estimation techniques typically relied on by cost of capital witnesses and Commissions estimate the expected rate of return, not the higher promised rate required to meet the *Duquesne* standard.

Q. Could you please elaborate on the meaning of the terms "expected return" and "promised return" as you have just used them?

A. Yes. The expected return is the return that investors expect to earn on an investment of comparable risk. The promised return, in contrast, is not the return that investors expect to earn, but includes a premium to compensate for asymmetric risks such as bond defaults. For instance, the promised rate of return on high yield bonds – the average of the coupon rates of the bonds – is about 200 basis points higher than the expected rate of return on the bond funds.

Q. Could you please summarize your conclusion with respect to these sharing proposals?

A. Yes. All three proposals are arbitrary and inconsistent with reasonable policy standards and the restructuring statute. They would impose severe financial hardship on Duquesne. They would be poor public policy and should be rejected.

The Company is Entitled to a Rate Cap Under Section 2804(4)(v)

Q. Which parties take issue with the Company's rate cap proposal for stranded cost recovery?

A. The OCA rejects the Company's rate cap proposal and substitutes an 18 percent rate reduction in its place. HSS also challenges the Company rate cap proposal, claiming that the Company has failed to meet its own test for meeting the provisions of Section 2804(4)(v).

Q. How do you respond?

A. The OCA and HSS positions are incorrect. The Company's rate cap stranded cost proposal is consistent with Section 2804(4)(v), is fully supported by the Company's own evidence, and is corroborated by the stranded cost analyses of OCA and the Industrials.

Q. Could you please elaborate on this conclusion?

A. Yes. Let me start with a brief description of the Company's rate cap recovery proposal so that its consistency with Section 2804(4)(v) is readily apparent. First, the Company is proposing to roll its authorized ECR into base rates, and to cap rates at that level. Second, the Company is proposing a minimum amortization commitment under the rate cap and, through the ROE spillover, additional amortization to the extent operating income exceeds the level necessary to achieve an 11.5 percent return on equity. Thus, during the rate cap period, the Company will not exceed its

authorized rate of return. Third, the rate cap will remain in effect until the earlier of December 31, 2005 or the date on which the Company has fully amortized its generation-related regulatory assets and market determined stranded costs. The Company has not proposed a rate cap through 2005 independent of the ultimate level of stranded costs, but rather has proposed a rate cap for only as long as is necessary to amortize its stranded costs. Contrary to HSS's contention, the possibility of "negative stranded costs" at the end of 2005 does not disqualify Duquesne from reliance on Section 2804(4)(v); under the Company's proposal such circumstances would result in earlier termination of the rate cap.

Q. But how do you know that the 2003 market valuation proposed by the Company is timely? Couldn't accelerated amortization under the rate cap through the end of 2003 exceed the amount required to allow the Company to recover its stranded costs?

A. The evidence put forward by the Company and by other parties suggests that a 2003 valuation is timely. Under its base case assumptions, the Company projects a remaining generation book value of $533 million at year end 2005, with a corresponding generation market value of only $110 million. Under these assumptions, a 2003 valuation date is clearly timely – the Company would have stranded costs remaining even with a rate cap through the end of 2005. Under the Company's high ceiling price case, end of year 2005 generation book value would again be $533 million, but the corresponding generation market value would be $765 million, and thus stranded costs would be negative $232 million. Clearly the rate cap would terminate prior to the end of 2005 in this circumstance, but that does not necessarily imply that valuation earlier than 2003 would be required. The table below

summarizes the generation asset book and market values at year end 2003 and 2004, as well as the net stranded cost exposure.

	12/31/03	12/31/04
Generation Book Value	$678 million	$624 million
Generation Market Value	$552 million	$661 million
Stranded Costs	$126 million	($37 million)

As the table illustrates, the Company would still have $125 million in stranded costs as of year end 2003, but by year end 2004 would have a negative $37 million in stranded cost. The implication of these figures is that even in the high ceiling price case, the Company would require the rate cap through the end of 2003 and well into 2004. A valuation in 2003 would still be timely for determining a mid- to late- 2004 rate cap termination date.

Q. You mentioned earlier that the OCA and Industrial stranded cost analyses corroborate the timeliness of the proposed 2003 valuation. Could you elaborate on that point?

A. Yes. As I have discussed at length above, these two parties have conducted detailed analysis of the Company's stranded costs and proposed specific one time administrative valuations. While I do not accept all of their assumptions and conclusions as discussed above, the question naturally arises: if the OCA or the Industrials are right about the future – how much of a rate cap will the Company require, and will a 2003 valuation still be timely?

Q. I take it that you have performed an analysis to answer this question?

A. Yes, I have. Let me start with the analysis based on the OCA's view of the world. For purposes of this analysis, I accepted all of OCA assumptions concerning the future value of generation – market prices, inflation, life extension economics, fossil decommissioning, avoidable costs and productivity improvements. I also accepted, for this purpose only, their lower ECR level, their 10 percent required return on equity, and their more levered capital structure. I did not accept their proposal to deny any return on generation stranded costs, for the reasons discussed above.

The resulting generation book value, generation market value, and net stranded cost are summarized in the table below for the years 2002 through 2005.

	12/31/02	**12/31/03**	**12/31/04**	**12/31/05**
Generation Book Value	$648 million	$567 million	$530 million	$445 million
Generation Market Value	$510 million	$552 million	$590 million	$632 million
Stranded Costs	$138 million	$15 million	($60 million)	($187 million)

The table shows that at year end 2005, generation market value exceeds remaining book value, and stranded costs are a negative $187 million. Under OCA assumptions, the Company would not require a rate cap through the end of 2005. Likewise, at year end 2004, generation value exceeds remaining book value by $60 million, and thus the Company would not require a rate cap through the end of 2004. At year end 2003, remaining book value exceeds generation market value by $15 million, and thus the Company would require a rate cap through the end of 2003 and into 2004 if OCA turns out to be right about the future. The valuation schedule proposed by the Company would support a timely determination to end the rate cap at the year end

2003. I also performed a sensitivity to the above analysis: I replaced the OCA capital structure and ROE assumptions with the Company's assumptions. These are issues that will be decided in this case, and they have a significant effect on the required term of the rate cap. Making just this one change in favor of the Company's position shifts the end of the rate cap from early in 2004 through the end of 2005. Thus, in both cases, the valuation schedule proposed by the Company is consistent with OCA's assumptions about the future.

Q. What about the analysis using the Industrials' assumptions to which you referred earlier?

A. Again, for purposes of this analysis, I accepted all of the Industrial's assumptions about the future value of generation – their market prices, their fuel and operating costs and their output levels. I did not accept the Industrials' sharing assumptions, for the reasons discussed above. The resulting book value, generation market value and stranded cost figures are shown in the table below as of year end 2002 through 2005.

	12/31/02	12/31/03	12/31/04	12/31/05
Generation Book Value	$691 million	$582 million	$501 million	$373 million
Generation Market Value	$169 million	$202 million	$241 million	$258 million
Stranded Costs	$522 million	$380 million	$260 million	$115 million

As the table shows, under the Industrial's assumptions about the future, the Company would have remaining stranded costs as of year end 2005, and thus would be entitled to the rate cap through the end of 2005. The 2003 valuation schedule proposed by the

2003. I also performed a sensitivity to the above analysis: I replaced the OCA capital structure and ROE assumptions with the Company's assumptions. These are issues that will be decided in this case, and they have a significant effect on the required term of the rate cap. Making just this one change in favor of the Company's position shifts the end of the rate cap from early in 2004 through the end of 2005. Thus, in both cases, the valuation schedule proposed by the Company is consistent with OCA's assumptions about the future.

Q. What about the analysis using the Industrials' assumptions to which you referred earlier?

A. Again, for purposes of this analysis, I accepted all of the Industrial's assumptions about the future value of generation – their market prices, their fuel and operating costs and their output levels. I did not accept the Industrials' sharing assumptions, for the reasons discussed above. The resulting book value, generation market value and stranded cost figures are shown in the table below as of year end 2002 through 2005.

	12/31/02	**12/31/03**	**12/31/04**	**12/31/05**
Generation Book Value	$818 million	$749 million	$713 million	$635 million
Generation Market Value	$93 million	$149 million	$213 million	$258 million
Stranded Costs	$725 million	$600 million	$500 million	$377 million

As the table shows, under the Industrial's assumptions about the future, the Company would have remaining stranded costs as of year end 2005, and thus would be entitled to the rate cap through the end of 2005. The 2003 valuation schedule proposed by the

Company would be timely if the Industrial's assumptions about the future turn out to be correct.

Q. This result surprises me. I thought generation market values under the Industrials' assumptions are higher than the Company figures, and that this would have an effect on the required length of the rate cap.

A. You are right about the first, and wrong about the second. The Industrials' generation market value estimate is higher than the Company's, largely because of higher market price assumptions from 1999 to 2005. But this difference in market price assumptions has no effect on the required length of the rate cap. This is because the market price between 1999 and 2005 has almost no effect on the end of year 2005 generation book value, on the one hand, and no effect on generation market value at year end 2005, on the other.

Q. Please explain.

A. As the above tables illustrate, the required length of the rate cap is determined by comparing the remaining generation book value at a particular point in time with the market value of generation at that same time. The end of the required rate cap period is the point where the two values are equal. During the generation rate cap period the remaining book value figure is largely independent of the market price for power – the remaining book value is instead a function of how much accelerated amortization can be funded under the rate cap. So, on the one hand, higher market price assumptions between 1999 and 2005 have almost no effect on the year end 2005 book value.

On the other hand, market price assumptions between 1999 and 2005 also have no effect on the value of generation at the end of 2005 – that is a function of market prices from 2006 on. And, as discussed above, the Industrials' market price forecast from 2006 on is actually below the Company's low ceiling price estimate. Thus, other things being equal, the Industrial generation value as of 2005 will be lower than the comparable Company figure.

The Proposed Annual CGC Determination is Appropriate

Q. Let's turn now to the CGC issue. Which parties take issue with the Company's proposed annual CGC determination?

A. Several parties criticize the Company's proposal, for two major reasons. First, the OCA and DII criticize the annual CGC determination, arguing that "certainty" considerations require a predetermined CTC schedule (and, hence, a CGC schedule under the rate cape) known to all parties in advance. Second, HSS, MAPSA, and OCA argue that the quantification methodology is flawed, either because the RFP will tend to understate the market value of power or because the Company fails to include a retail marketing credit in the CGC, to take account of the marketing expenses that will be incurred by competing retail marketers, and to ensure that there is a reasonable opportunity for them to compete against the incumbent's rate cap service.

Q. How do you respond to these criticisms?

A. Neither of the criticisms is valid. First, while certainty is an understandable objective, it cannot be achieved without distorting customer choice and jeopardizing stranded cost recovery during the transition so long as service at the rate cap level is available

from the incumbent. These problems are even more severe if the CGC is predetermined using administrative market price estimates as OCA and DII propose. Second, the quantification criticisms are unfounded. The RFP process will not understate the value of power, as discussed in more detail by Mr. Lahtinen. Until such time as an acceptable market index is available, the RFP process is the best way to set the CGC. As discussed by Mr. Marshall, the Company is willing to submit the proposed RFP procedures and contracts to the Commission for approval. A further credit for retail marketing expense as proposed by OCA and MAPSA will distort competition and could jeopardize the Company's opportunity for stranded cost recovery as well. The magnitude of OCA's proposed credit far exceeds the level requested by an ENRON affiliate for a limited retail pilot, let alone a full access scenario. If the policy goal is to ensure that many customers choose a new supplier, a better solution is to eliminate the option to take service at the rate cap level, and to substitute a market-priced option in its place.

Q. Let's start with the certainty issue. Why would a predetermined CGC distort customer choice and jeopardize stranded cost recovery during the transition period?

A. The answer lies in the interaction between the CGC and the rate cap. Recall that the statute gives every customer a valuable option – the right but not the obligation to take service at the rate cap level during the pendency of the transition period, and to return to service at the rate cap level even after they have switched to another supplier. This means that at any point in time, a customer contemplating a choice between rate cap service and another supplier will be comparing, among other things, the level of the CGC compared to the price offered by the potential supplier. If the

CGC is set in advance, as OCA and DII propose, it is very likely that the predetermined CGC will diverge from the actual market price, perhaps substantially. What will happen then? If the actual market price is higher than the predetermined CGC, suppliers will have a difficult time competing against the rate cap service. Both suppliers and customers will likely complain to the Commission that the CGC is biased in favor of the incumbent, and needs to be increased. They will be right. On the other hand, if the actual market price is lower than the predetermined CGC, then neither customers nor suppliers will complain. It will be easy to compete against the rate cap service, but this competition will not be economic either, and will result in reduced levels of stranded cost recovery. Under this circumstance, the utility will likely complain to the Commission that the CGC is too high and should be reduced – and it will be right. These problems will only be more severe if the CGC is predetermined using an administratively- determined market price forecast, as OCA and DII propose. Their two market price forecasts are significantly different from each other during the transition period, and both are above the 8 year forward price that is the only market evidence in this proceeding. The probability that the predetermined CGC and the actual market price will diverge seems a virtual certainty. The only way to avoid these problems is to set the CGC on an annual basis using market evidence as the Company has proposed.

Q. You stated earlier that certainty was an understandable objective. Is there a reasonable way to provide increased certainty as to what the CGC will be?

A. Yes, there is. The Company has already proposed one such approach in the Pilot, which was attacked by many parties (including some now arguing for certainty) and

rejected by the Commission. Under that proposal, customers choosing to waive their right to return to rate cap service could have their CGC predetermined for the remainder of the transition period based on the then current forward market price. This option would provide increased levels of certainty while avoiding the competitive problems described above. But given the hostile reception this option received in the Pilot, the Company has not proposed it in this proceeding.

Q. What about the first of the quantification criticisms; that the RFP process itself is flawed and that it will understate the market value of power?

A. Mr. Lahtinen responds to these criticisms in some detail, but I will offer a few comments. First, the Company made every effort to maximize the value of the power by offering a flexible product – fully dispatchable between 50 percent and 100 percent capacity factor – as well as a product that would be perceived as offering liquidity to purchasers. The RFP was widely advertised and attracted interest and participation from some of the largest power marketers in the country. Second, while the 1998 RFP results may well have been influenced by the current market structure in ECAR and by current FERC transmission pricing policies, that is the real power market today. Duquesne cannot sell its power at higher prices today simply by wishing that market reforms were already in place or that more markets were open at retail. If and as these conditions change during the transition period, and if and as they influence the market price, those effects will be reflected in the auction results. Finally, the Company is willing to replace the RFP process with an acceptable published index or forward price. But in the interim, the RFP process proposed by

the Company, subject to the review and approval of the Commission, is the best alternative.

Q. What about the second quantification criticism concerning the need for a retail marketing credit? Why would such a credit distort competition and jeopardize the Company's opportunity for stranded cost recovery?.

A. The role of the CGC, including any proposed additional credits, is to establish the proverbial "level playing field" for efficient competition. By efficient competition, economists mean competition that takes place on the basis of marginal costs, not sunk costs. When a customer decides to take service from Duquesne at the rate cap price, the marginal costs incurred by Duquesne are the opportunity cost of not having that power available to sell in the wholesale market. This is precisely the opportunity cost that the RFP measures, adjusted only for the customer's load shape and for distribution losses. Duquesne will not be marketing its rate cap service, so there are no marginal marketing costs to be added to the wholesale opportunity cost. Likewise, Duquesne Light Company has no capability or authority to sell power at retail on an unregulated basis, so there is no retail opportunity cost that would be appropriate to measure. Efficient competition requires that the customer compare Duquesne's marginal cost of serving the customer – the RFP-based CGC – against the pricing and other product attributes offered by the competing supplier. Duquesne's proposal accomplishes precisely that.

Q. What would be the effect of adding a retail marketing expense credit to the CGC as proposed by OCA and MAPSA?

A. The effect would be to artificially inflate the marginal cost of providing rate cap service above its actual level, distorting the comparison between rate cap service and the offering of the competing supplier. This would result in subsidized competition, rather than efficient competition, with Duquesne providing the subsidy to the competing suppliers. To illustrate, under Duquesne's proposal, customers will switch to a new supplier when the attributes and pricing of the competitive offering are more valuable to the customer than rate cap service priced at its marginal or opportunity cost. Under the OCA/MAPSA proposals, customers will switch to a new supplier when the attributes and pricing of the competitive offering are more valuable to the customer than rate cap service priced at its marginal cost plus an allowance for its competitors' marketing costs. More customers may switch, but there can be no assurance of improved efficiency. In addition, the Company's opportunity for stranded cost recovery is reduced.

Q. How is the opportunity for stranded cost recovery reduced?

A. Under the OCA/MAPSA proposals, when a customer switches from rate cap service to a new supplier, the Company loses revenues equal to the CGC plus the retail marketing credit, as compared to the customer continuing to take rate cap service. The only costs that go away are the cost of purchasing power to supply that customer (or the extra revenues from having more power to sell at wholesale). This leaves a gap equal to the retail marketing credit, lost revenue that would otherwise have been available for amortization of stranded costs. The larger the retail marketing credit, and the more customers that switch, the larger the revenue shortfall.

Q. Do you have any comments on the size of the proposed retail marketing credits?

A. As should be clear from the foregoing, any subsidy of this type, regardless of size, is a bad idea. But the potential magnitude of the subsidies suggested here are particularly egregious. As a yardstick for comparison, I have in mind a proposal by Portland General Electric Company, an affiliate of ENRON, "to provide a monthly credit to Energy Service Providers (ESPs) during the introduction of the Company's Customer Choice Program." The size of the credit varies by type of customer and by number of participating customers, but would average around $2 per MWH if applied to Duquesne. Under the Portland proposal, the credit was to be available only for a short period of time (approximately one year) prior to the date of full customer choice. Contrast this proposal with those of parties in this proceeding which seek to institutionalize credits that are as much as twice as large for the seven year duration of the transition period. Measured against the Portland General yardstick, the proposals for a retail credit in this proceeding are excessive.

Q. But what if the Company's proposals are adopted and not many customers switch suppliers? Wouldn't that indicate that some type of additional credit is required?

A. No, that would not be the best solution. The problem is that there are competing policy goals during the transition: providing customers a stable, predictable and familiar option during the transition, on the one hand; and creating an environment where customers choose from among competitive suppliers in significant numbers, on the other. The restructuring statute places heavy emphasis on the first of these goals. It provides the rate cap option, which is stable, predictable, familiar and perhaps attractive to many customers. That of course makes the job of competitive suppliers much more difficult; they must offer something more attractive than the rate cap

option. But if the predominant policy goal is to assure that significant numbers of customers choose competitive suppliers, the right answer is not to subsidize switching, but rather to revisit the rate cap option. A bottom up approach, where customers choosing default service pay a delivery charge, a CTC charge, and a market-determined power charge might result in more customer switching without any inefficient subsidies. Of course, the "cost" of this approach would be the loss of any rate cap safety net. Default service prices might turn out to be higher or lower than the rate cap level. But if the goal is significant numbers of customers choosing competitive suppliers, this is an option worth considering.

Q. Does this conclude your testimony?

A. Yes, it does.

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VOLUME II

Duquesne Statement No. 4

Pittsburgh 2-6-98
CSA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

0235211

Direct Testimony
of
Morgan K. O'Brien

Contents:

Regarding Regulatory Assets, Decommissioning Costs and 1996 Revenues, Expenses and Rate Base

DIRECT TESTIMONY OF MORGAN K. O'BRIEN

Q. Please state your name and business address.

A. Morgan K. O'Brien. 411 Seventh Avenue, Pittsburgh, PA 15219.

Q. By whom are you employed and in what capacity?

A. I am employed by Duquesne Light Company ("Duquesne" or "the Company") as its Controller and Chief Accounting Officer.

Q. Describe your responsibilities.

A. In general, I oversee Duquesne's accounting organization. This organization consists of departments which include regulatory reporting, tax, corporate accounting, accounts payable, customer accounting, valuation and property records, and payroll, all of which report directly to me. I establish and direct all corporate accounting policies and procedures. I also am responsible for ensuring accuracy and completeness of all financial statements and all regulatory filings dealing with financial information.

Q. Please state your background with Duquesne.

A. I have been with Duquesne since September, 1991. During that time I have been employed first as Manager of Taxes and later, Assistant Controller before being named Controller of the Company in 1995.

Q. Please describe your professional background before coming to Duquesne.

Prior to joining Duquesne, I held the position of Assistant Vice President of Corporate Taxes at PNC Bank in Pittsburgh. Prior to PNC, I was employed as a Manager in the Pittsburgh office of Deloitte & Touche, a public accounting firm. I have also lectured numerous times on various accounting and tax issues to various professional accounting

groups. I also taught numerous undergraduate accounting courses in the University of Pittsburgh's School of Business.

Q. What is your educational background?

A. I hold a Bachelor of Science Degree in Business Administration, as well as, a Masters of Science Degree in Taxation. Both degrees were awarded from Robert Morris College in Pittsburgh.

Q. Do you hold any professional licenses and are you a member of any professional organizations?

A. I am a Certified Public Accountant. Although I am currently in an inactive status, I previously was an active member of the American Institute of Certified Public Accountants, as well as, Pennsylvania Institute of Certified Public Accountants. I am currently a member of the Edison Electric Institute Chief Accounting Officers Committee.

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to present all relevant facts concerning the Company's regulatory assets, including both nuclear and fossil decommissioning, which will become "stranded" as a result of the various provisions of the Electricity Generation Customer Choice And Competition Act ("the Act") and for which the Company seeks recovery. I will also provide an explanation of the financial impact of an adverse order relating to the Company's request to recover its stranded costs relating to generation, including regulatory assets, nuclear and fossil decommissioning and investments in generating assets. I will also provide the Company's revenue requirements calculation including the functional assignment of costs into generation, transmission and

distribution, which Mr. Lahtinen will then use to develop the Company's cost of service study. Finally, I will also describe and support various of the Company's accounting and financial data submitted in response to the filing guidelines (Appendix A) for electric utility restructuring in the Commission's order issued in Docket No. M-00960890.

REGULATORY ASSETS & DECOMMISSIONING OF POWER PLANTS

Q. Please describe the Company's claim for recovery of certain regulatory assets, as well as decommissioning costs associated with nuclear and fossil power stations.

A. First, the Company is seeking to recover the entire balance of its generation related regulatory assets over the nine year transition period. Second, the Company is seeking to recover annually over the transition period its current level of nuclear decommissioning costs (including the $5 million increase as part of the Ft. Martin sale agreement with the Commission). The Company is not foregoing the potential to further mitigate the unfunded balance of nuclear decommissioning liability during the transition period. Third, the Company is not seeking to recover any of its unfunded fossil decommissioning costs over the transition period (unless either future mitigation allows for the recovery or future market prices allow for the recovery). Fourth, the Company is proposing to treat the unfunded fossil decommissioning and, if any, the unfunded nuclear decommissioning as a reduction in any residual value of the generation stations at January 1, 2006.

Q. You referred previously to the Company's claim for the recovery of certain regulatory assets, as well as decommissioning costs associated with nuclear and fossil power stations. Please explain what you mean by regulatory assets.

A. In short, a regulatory asset is created when a company is permitted by accounting rules (most notably SFAS 71) to book an "asset" for a sum to be collected in the future for which the relevant regulator has issued a valid order which provides for the certainty of recovery of that sum. Generally, the basis for the creation of a regulatory asset is that the regulator agrees that a regulated company has the right to the current recovery of a certain sum in rates but, for various reasons, determines that such recovery should either be deferred to a date certain in the future or should be amortized over a certain number of years.

Q. What is the basis for the Company's claim for recovery of its regulatory assets, as well as its claim for decommissioning of its generating stations?

A. There are several. First is the Act, itself. Section 2808(C)(1) states that, "in determining the level of transition or stranded costs that an electric utility may recover through the competitive transition charge, the Commission shall apply the following principles: (1) the Commission shall allow recovery of regulatory assets and the unfunded portion of the utility's projected nuclear generating plant decommissioning costs.

Q. Are there other reasons why the Company should be permitted to recover through a competitive transition charge its regulatory assets which become stranded as a result of the electric restructuring?

A. Yes, there are several. The first reason is that the Commission has already determined that these costs are due the Company and should be recovered through rates. As I will show, in each instance the Commission has explicitly made this determination or has done so implicitly by determining the schedule for cost recovery, either at a date certain or through an amortization schedule. That the Company has not yet recovered all of these

costs is simply the result of a regulatory determination that requires Duquesne to forego immediate recovery of those Commission-approved costs. The second reason is fundamental fairness. The Company has provided the benefits associated with the regulatory assets to ratepayers without yet recovering all of the attendant costs. It is only proper that the Company should be permitted to recover the attendant costs which would otherwise be rendered unrecoverable by the restructuring of the industry. The third reason is that the Company will be required to write off its regulatory assets without the certainty of recovery through the competitive transition charge. This would create a very dire financial situation for the Company. The fourth reason is that investors and the credit-providing community have relied on the Commission's assurance that the Company would be permitted to recover these costs. Indeed, that is why the accounting profession permitted Duquesne to book these costs as regulatory assets. The failure to live up to this bargain would have very serious consequences for any entity looking to secure financing for business activities in Pennsylvania. [I discuss these consequences in more detail later in my testimony.]

Q. Is the Company seeking both "return of and on" all regulatory assets?

A. No. The "early window" costs associated with the nuclear plants was specifically denied a return on in previous Commission decisions. The Company is not seeking a return on these costs but rather just the recovery of these previously incurred costs. In addition, there are a number of other regulatory assets which Duquesne is not including as rate base. These include deferred fuel expense, D.O.E. decontamination & decommissioning assessment, as well as any regulatory asset which has not been actually incurred prior to the time of the proposed collection period.

Q. Does this mean the Company is seeking both a "return of and on" the regulatory tax receivable? If so, why?

A. The literal answer is yes. The Company is seeking both a "return of and on" the regulatory tax receivable. The reason for this is that the corresponding additional deferred tax liability associated with this future tax receivable has reduced the Company's claim for its plant-in-service rate base. Thus, the Company is reducing the otherwise sought plant-in-service rate base return while at the same time increasing the return it is seeking regarding regulatory assets by the same dollar amounts. These two adjustments completely offset one another, one increasing the return and one decreasing the return.

Regulatory Assets & Decommissioning Expenses

Q. Please list each of the generation related regulatory assets for which the Company seeks recovery and the associated claim.

A. They are as follows:

	Generation $	PUC Order
Regulatory Tax Receivable	$244,800,000	R-860378
Unamortized Premium on Reacquired Debt	56,949,000	R-870651
Unamortized Debt Expense	5,476,000	R-870651
Beaver Valley No. 2 Premium on Reacquired Debt	30,059,000	R-870651
Deferred Rate Synchronization Costs	41,446,000	R-870222
Injuries and Damages	9,053,000	R-870651
Compensated Absences	7,954,000	R-870651
Def'd Nuclear Maintenance Outage Costs	13,461,000	R-870651
DOE Decontamination and Decommissioning	9,780,000	RM93-18-000*
Deferred Coal Costs	12,130,000	P-890386/387
Deferred Caretaker Expenses	6,772,000	P-900485
BV2 Training Costs	2,616,000	R-870651
FAS No. 106 Costs	22,428,000	
Cold Reserved Units	106,800,000	R-860378
Warwick Mine Investment	15,295,000	R-870651
Pilot Program Incentive Credit	4,350,000	
Customer Education	2,000,000	
Transition Filing	1,000,000	
Transition Implementation Costs	11,000,000	
Low Level Rad. Waste	2,274,000	R-870651
Total Regulatory Assets	$605,643,000	

* FERC Order

	Nuclear Decommissioning	281,000,000
	Fossil Decommissioning	274,400,000
	Total Regulatory Assets & Decommissioning	$1,161,043,000

Generation Related Regulatory Assets

Q.. Please explain the basis of the Company's claim for the Regulatory Tax Receivable.

A. In Pennsylvania, utility rates historically have been set based upon the doctrine of "actual taxes paid," except where Federal Income Tax law requires normalization of tax benefits. In its order in Docket R-860378, the Commission required Duquesne to flow back to its customers the then-current period State Tax benefits associated with accelerated depreciation for income tax purposes. The order further required the Company to flow through on a current basis the federal income tax benefits associated with basis differences between ratemaking balances and the income tax basis of plant. This treatment was reconfirmed in the order issued by the PUC in Docket R-870651. Pursuant to its required adoption of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (SFAS 109), Duquesne in January, 1994 recorded an initial balance of $550 million reflecting the reversal of these previously flowed-through income tax benefits. This regulatory asset was booked in recognition of the fact that the tax benefits will "turn around" in the future, leading to a higher tax expense which must be paid by the Company. At that time, however, the plant which gave rise to the accelerated depreciation will no longer be in jurisdictional rates. Ratepayers, therefore, would have gotten the benefit of lower rates in the past due to the tax advantages of the accelerated depreciation, but also would be able to avoid the higher tax

bill in the future when the assets which gave rise to be depreciation become deregulated. This result is incompatible with the even-handed treatment envisioned in the PUC's past orders. This regulatory asset simply recognizes the tax expense associated with the reversal of the timing differences between ratemaking accounting and tax accounting -- an expense which, otherwise, would be inequitably avoided by the Company's customers.

Q. Please describe the regulatory asset for the Unamortized Premium on Reacquired Debt.

A. From time to time it becomes advantageous to require existing long term debt and issue new debt at lower interest costs. This reacquistion of high cost debt offers direct benefits to customers in the form of a lower cost of service. The Unamortized Premium on Reacquired Debt represents the excess of the reacquisition price over the net carrying amount of First Mortgage Bonds, Debentures, and Pollution Control Obligations. In recognition of the benefits to ratepayers resulting from the refinancing, the PUC has permitted the Company to recover these costs through an amortization over the life of the new debt issuance. This accounting has been consistently applied throughout Duquesne's ratemaking history and was most recently reconfirmed in the order issued in Docket R-870651. Ratepayers have already enjoyed the savings that arose as a result of the Company's refinancing of debt at lower interest rates. It would be patently unfair to deny the Company the recovery of the costs it had to incur to produce those savings.

Q. Please describe the regulatory asset arising from Unamortized Debt Costs.

A. The Company incurs costs associated with the issuance of First Mortgage Bonds, Debentures and Pollution control Obligations. Instead of permitting the Company to recover these costs on a current basis, the Commission has consistently required that they be amortized over the life of the underlying bonds. This rate treatment has been applied

consistently to Duquesne, the most recent order authorizing it having been issued in Docket R-870651. Here, again, this is a case of the Company having paid an expense and the PUC having determined that it should be recovered over a number of years. Due to the restructuring, however, the Company will not be able to recover fully the Unamortized remainder of the expense. Elementary fairness demands that Duquesne be permitted to recover the remainder of this expense which was undertaken in the service of the ratepayers.

Q. Please describe the Premium on Reacquired Debt Associated with Beaver Valley No. 2.

A. These costs represent the excess of the reacquisition price over the net carrying amount on the bonds issued in conjunction with the sale and leaseback of the Beaver Valley Nuclear Unit No. 2 generating station. Instead of allowing a current recovery of this expense, these costs are being amortized over the life of the new issue of lower cost debt. As in the case of the Premium on Reacquired Debt, for which the accounting treatment has been consistently applied to Duquesne, this treatment was specifically adopted in the order issued in Docket R-870651.

Q. Would you please continue with a description of Deferred Synchronization Costs?

A. In Docket R-870222, the PUC granted Duquesne's request for "early window" rate treatment for two nuclear generating plants, Beaver Valley Unit No. 2 and Perry Unit No. 1. The "Early Window" refers to the fact that the plants went into commercial operation before the date on which rates were adjusted to include the plants. The early window rate treatment allowed the Company to defer the costs and seek recovery, over time, of the costs incurred between the dates of commercial operation and rate recognition. As part of Duquesne's sale of its interest in the Fort Martin Plant, the PUC approved a

comprehensive settlement agreement under which the Company, among other things, agreed to write off $9.0 million of the Deferred Rate Synchronization costs and amortize the remaining balance over the 10 year period concluding in 2006. The electric restructuring effort will make it impossible to recover fully the remaining early window amortization unless it is included in the CTC. The failure to permit such recovery would be violative of the terms of the Ft. Martin agreement which has provided tangible benefits to customers, including, but not limited to, a rate freeze until 2001.

Q. Please continue your description of regulatory assets with the category "Injuries and Damages."

A. These costs relate to the Company's workers compensation liability. For financial accounting purposes, Duquesne is required to book an accrual for the cost of these benefits. Despite the fact that ratemaking is based almost entirely on accrual accounting, the Commission, permits the Company to recover these costs, through rates, only on a "pay-as-you-go" or "cash" basis. This rate treatment, which was most recently confirmed in the Company's last rate case in Docket R-870651, produces a shortfall between the higher accrual for this expense and its cash recognition. If the Company's generation had remained part of the regulated assets, Duquesne would recover the difference between the cash and accrual basis of this expense over time. Because the generation portion is being "deregulated," however, Duquesne will not be permitted to recover these amounts. In effect this is simply a timing issue, much the same as the FAS 106 issue and basic fairness requires that Duquesne be permitted to recover the shortfall.

Q. You mentioned "Compensated Absences" as another regulatory asset. Is the treatment indicated for Compensated Absences like that for Injuries and Damages?

A. Yes. The costs for Compensated Absences relate to Duquesne's accrued liability for its employees' right to receive compensation for future absences when that compensation is attributable to service already rendered. Although the Company must book an accrual for these expenses, the Commission only permits the Company to recover the cash basis of the expenses in rates. The Company is then permitted to book a regulatory asset reflecting the difference between the accrual basis and cash basis of the expense. This rate treatment was confirmed in the Company's last rate case in the order issued in Docket R-870651. The continued recognition of the regulatory asset and recovery of the portion rendered unrecoverable by electric restructuring, is necessary to maintain consistency with this long-established ratemaking protocol.

Q. Please continue with a discussion of Deferred Nuclear Maintenance Outage Costs.

A. Duquesne has historically recovered the costs of maintenance outages for its nuclear fueled generating plants over the ensuing operating period. In other words, the Company is permitted to amortize its costs over the period between the last outage and the next scheduled outage. Under this ratemaking treatment, the Company must incur the expense but must defer recovery of the entire expense over a period of years. This regulatory asset simply reflects the Unamortized, and hence, uncollected, cost of the most recent outages at the Company's nuclear plants. Inasmuch as the Company has already incurred and paid the expenses, it is only fair that it be permitted to recover the Unamortized balances.

Q. Please explain the rationale for the recovery of the regulatory asset for DOE Decontamination and Decommissioning Expenses.

A. The Department of Energy is collecting funds for utilities to pay for the decommissioning of its uranium enrichment facility. In Docket RM93-18-000 the FERC authorized the recording of a regulatory asset for this liability and the collection of the liability over time through a surcharge to utility customers. Unless the PUC recognizes the Unamortized amount as a regulatory asset which should be collected through the CTC, Duquesne will owe the liability to the DOE but its customers will escape from having to reimburse Duquesne through the surcharge. This would be an unfair result which would run counter to FERC's orders.

Q. Please continue with a discussion of Deferred Coal Costs.

A. In Docket Nos. P-890386 and P-890387, the PUC imposed a cap on the amount of fuel costs that Duquesne could recover through the ECR fuel adjustment rate. The Company, however, was permitted to defer for future recovery the amount of energy costs in excess of the cap. In other words, although the Company actually incurred fuel charges in excess of the cap, it was not permitted a current recovery of those costs. The quid pro quo for this arrangement was that Duquesne would be permitted to defer and recover these costs at some point in the future. Electric restructuring, however, will render these costs unrecoverable due to the deregulation of generation. Accordingly, the Company must be permitted to recover these costs through the CTC.

Q. Please describe the FAS No. 106 Cost being claimed as stranded costs.

A. In addition to normal pension benefits, Duquesne provides certain heath care benefits and life insurance for some retired employees. Company-provided health care benefits terminate when covered individuals become eligible for Medicare benefits or reach age 65, whichever comes first. FAS No. 106 was issued in December, 1990 and became

effective for Duquesne beginning in 1993. This statement required the accrual established for these types of post-retirement benefits. Consistent with the Commission's guidelines for implementing FAS No. 106, the Company is amortizing the liability required upon adoption of this statement over 20 years. Due to the change in legislation, this liability which relates solely to employees liability incurred prior to the date of legislation must be now recovered over the transition period of the Act rather than the original 20 year period.

Q. Please discuss Deferred Caretaker Costs.

A. In Docket P-900485, Duquesne requested, and the PUC approved, deferred accounting treatment for preservation costs associated with maintaining the Philips and Brunot Island generating plants. The Company was specifically granted the right to seek recovery of these costs upon the return to commercial operation of the plants. With restructuring, these plants will be "deregulated" and Duquesne will never be able to recover the costs of preserving the plants for future needs of its customers unless it can recover the costs through the CTC. Fairness requires this be done.

Q. Please describe the Company's claim related to the "cold reserve" units at Brunot Island and Phillips Power Stations.

A. These units (Brunot Island 3 and 4; Phillips 1,2,3 and 4) were put in cold reserve in 1986. The plants were put into cold reserve instead of being retired because the Company believed the units still had economic value to customers. This belief was shown to be justified by the willingness of the GPU Companies to purchase part of the capacity several years ago (in a transaction that ultimately was not consummated). However, because of the transition to a competitive market, these cold reserve units now

appear to be uneconomic to operate on a production cost basis. Specifically, the capital improvements needed to restore these units to operation together with their going forward expected operating costs ("to-go" costs) exceed the expected market prices, which precludes the economic operation of these units in the future.

Q. What would have been the result had the Company not placed the units in "cold reserve" status, but rather had retired the units in 1986.

A. The net plant value would have reduced the applicable plant depreciation reserve balance and, thus, would have been amortized over the remaining life of the applicable plant accounts through the operation of the remaining life method. Stated another way, rate recovery for these net plant balances would have occurred over the remaining life of the other operating fossil power stations from customers.

Q. How did you calculate the Company's stranded cost claim for the "cold reserved" units.

A. The Company has included the net undepreciated cost of these units in its claim for stranded costs of $106,800,000.

Nuclear Decommissioning Expenses

Q. What are nuclear decommissioning expenses?

A. Nuclear decommissioning expenses are the costs to dismantle, decontaminate, remove and dispose of nuclear generating facilities at the end of their useful lives. Nuclear decommissioning, like all aspects of nuclear plant operation, is heavily regulated by the Nuclear Regulatory Commission ("NRC"). Nuclear decommissioning expenses are estimated on the basis of the studies prepared by qualified experts with special knowledge of the planning, engineering and management of decommissioning projects and the applicable NRC requirements.

Q. How are nuclear decommissioning expenses reflected for ratemaking and book purposes?

A. For ratemaking purposes, the total estimated nuclear decommissioning expense for a nuclear generating unit is recovered over the estimated useful life of that unit. For book accounting purposes, the amount recorded as an annual expense for decommissioning is based upon the amount included in rates charged to customers. Under Generally Accepted Accounting Principles ("GAAP"), utilities are not required to record their total estimated decommissioning expense as a liability, although the Financial Accounting Standards Board ("FASB") is currently reviewing whether it is appropriate to record such liability.

Q. What is done with the amounts collected from customers for nuclear decommissioning expenses?

A. As required by NRC regulations and applicable Commission orders, the amounts collected from customers are deposited in external decommissioning trust funds, which can be used only for future decommissioning costs. Currently, the bulk of the money collected is placed in "qualified nuclear decommissioning trust funds" as defined by the Internal Revenue Code. The Company claims a current tax deduction for the amounts paid into a qualified decommissioning trust fund for both federal and state tax purposes. In addition, the earnings on the qualified decommissioning trust fund balances are not treated as taxable income of the Company. Instead, they are taxed at a favorable 20% rate for federal income tax purposes (as opposed to the Company's federal tax rate of 35%) and are taxed at the personal income tax rate of 2.8% for Pennsylvania income tax purposes (as opposed to the corporate net income tax rate of 9.9%).

Q. What is the Company's estimated nuclear decommissioning expense?

A. The Company's total estimated nuclear decommissioning expense, as of December 31, 1996, is $281,000,000 (in year end 1996 dollars).

Q. How was the total nuclear decommissioning expense estimate determined?

A. The nuclear decommissioning expense estimate was based on the results of site-specific studies of Perry and Beaver Valley nuclear power plants that were prepared by Mr. Thomas S. LaGuardia, President of TLG Services, Inc. Mr. LaGuardia estimated total decommissioning expenses, as of December 31, 1996 of $312 million (in 1996 dollars).

Q. How much of the Company's estimated nuclear decommissioning expense is funded as of December 31, 1996?

A. As of December 31, 1996, the aggregate trust fund balances were approximately $ 33.7 million. The Company is currently recovering in rates approximately $ 9 million per year of nuclear decommissioning expense, which is being deposited in the trust on an ongoing basis.

Q. Given the estimated nuclear decommissioning costs at December 31, 1996, and the trust fund balance on the same date, how did you calculate the Company's stranded cost claim for nuclear decommissioning?

A. The Company has claimed the unfunded portion of the projected nuclear generating plant decommissioning costs as of December 31, 1996 as stranded. However, as previously outlined the Company is proposing to continue to fund approximately $9 million per year on an ongoing basis until January 1, 2006. At that time, the Company is proposing to treat the unfunded balance as a reduction in any residual value of its generation plant.

FOSSIL DECOMMISSIONING

Q. What are fossil decommissioning expenses?

A. Fossil decommissioning expenses are the costs to dismantle, remove and dispose of fossil-fired steam generating facilities at the end of their useful lives. Like the corresponding expenses for nuclear facilities, fossil decommissioning expenses are estimated on the basis of studies prepared by qualified experts with special knowledge and expertise in the areas of planning, engineering and managing such projects.

Q. How are fossil decommissioning expenses reflected for ratemaking and book purposes?

A. Fossil decommissioning expenses are treated as a cost of removal. Under prior historical Pennsylvania regulatory practice, neither the cost of removal nor any salvage value is recognized until an asset is retired and the cost of removal is actually incurred. The actual cost of removal less any associated salvage value (net negative salvage) is recorded as a deduction from accrued depreciation and, thus, is amortized over the remaining life of the applicable plant accounts through the operation of the remaining life method. Stated another way, both the expense recognition and rate recovery for fossil decommissioning expenses have been after the fact. Because of the ratemaking and accounting procedures explained above, there has been no recognition of the decommissioning costs that will be incurred upon retirement of the Company's fossil-fired generating units. Thus, unlike nuclear decommissioning expenses, the Company's fossil decommissioning expenses have not been funded.

Q. What is the estimated fossil decommissioning expense for which the Company is financially responsible?

A. For fossil-fired steam generating units, the Company estimates decommissioning expenses of $ 274.4 million.

Q. Given the estimated fossil decommissioning costs and the fact that there has been no funding of these amounts, how did you calculate the Company's stranded cost claim for fossil decommissioning?

A. The Company has claimed the unfunded portion of the projected fossil generating plant decommissioning costs as of December 31, 1996 as stranded. However, as previously outlined the Company is proposing as of January 1, 2006 to treat the unfunded balance as a stranded cost which would reduce any residual value of its generation plant.

Q. How was the total fossil decommissioning expense estimate determined?

A. Fossil decommissioning expenses for the units listed in Mr. Laguardia's testimony are based on the site specific studies performed by Mr. LaGuardia as of December 31, 1996.

Q. Will the transition to competition change the way in which the Company accounts for fossil decommissioning expenses?

A. Yes. When the Statement of Financial Accounting Standards No. 71 ("SFAS 71"), Accounting for the Effects of Certain Types of Regulation, ceases to apply to the Company's generation function, the Company will have to record the liability and accrue this expense each year over the operating life of the fossil generating plant.

EFFECT OF AN ADVERSE ORDER ON FINANCIAL CONDITION

Q. You previously stated that the write-off of the Company's assets could create a dire financial situation. Please explain.

A. After reducing the carrying value of an asset, the effect of any asset write-off is a reduction in the current period earnings. This reduction in current period earnings would directly reduce the equity of the Company. The effect of this reduction in equity, if it caused Duquesne's equity to fall below required minimum levels, would be to cause Duquesne to default on its debt covenants, including, potentially, covenants made under Duquesne's sale and leaseback agreement for its Beaver Valley Unit No. 2. A default in these covenants would have a number of detrimental effects on the Company including the potential of forcing Duquesne into a bankruptcy proceeding. At a minimum, a write-off could adversely affect Duquesne's credit ratings which could raise the cost of future borrowings. An adverse order also could depress the Company's stock price, thereby reducing the value of the Company's publicly traded stock and potentially limiting the Company's ability to raise new capital.

Q. When would the Company incur a write-off loss in its financial earnings?

A. The Company would incur a write-off loss in its current period earnings either when an asset is impaired or deemed worthless. Specifically in this scenario, the impairment of either a regulatory asset or a generating plant investment would cause the Company to incur a write-off loss.

Q. Under what circumstances can a regulatory asset become impaired causing the Company to recognize a loss for financial purposes?

A. Once a regulatory asset is created, subsequent rate actions of a regulator can reduce or eliminate the value of a regulatory asset. If a regulator excludes all or part of a cost from allowable costs, the carrying amount of any asset recognized pursuant to Statement No.

71 would be reduced, and the Company would recognize an immediate loss to the extent of the excluded costs.

Q. Describe when an impairment loss should be recognized relating to generating assets.

A. When events or changes in circumstances indicate that the carrying amount of the generating asset may not be recoverable, the Company must also conduct a review for impairment.

Q. What is the basis for this determination?

A. FASB Statement No. 121 establishes the rules for recognition of impairment for long lived assets.

Q. How does Statement No. 121 determine whether generating assets are impaired?

A. To test for impairment, the Company should compare future cash flows from the use and ultimate disposal of the asset to the carrying amount of the asset. Impairment exists when the expected future nominal (undiscounted) cash flows excluding interest charges are less than the carrying amount.

Q. What is the impact to the Company's financial statements if an asset fails an impairment test?

A. If an impairment is found to exist, the impairment loss to be recorded is the amount by which the assets carrying amount exceeds its fair value. The best estimate of fair value are quoted market prices.

Q. Please explain how a current period earnings loss reduces the Company's equity section of its balance sheet.

A. The equity section of a Company's balance sheet has two basic components: (i) contributed capital and (ii) earned capital. Contributed capital consists of preferred and

common stock along with additional paid-in capital. The basic source of earned capital is income from operations. Any losses from operations directly reduces the earned capital component of equity.

Q. Based on the outlined accounting rules, what would be the impact of any disallowance of the Company's claim for stranded costs?

A. The disallowance of any stranded costs sought to be recovered in this filing could cause the Company to incur an immediate financial impairment loss to either its generation related regulatory assets or its investment in generation plant assets or both groups of assets, depending on the nature of the disallowance. As discussed, such write-off would reduce current period earnings and equity of the Company in the quarter in which the order disallowing the claim becomes final.

PLANT IN SERVICE AND DEPRECIATION EXPENSE

Q. Have the Company's generating plants been reflected in rate base in rate orders of the Commission?

A. Yes. In the order in Docket R-870651, the Company's last fully litigated rate case, the Commission authorized rates which reflected the following plants: Elrama, Cheswick, Ft. Martin, Sammis, Eastlake, Mansfield, Beaver Valley Unit Nos. 1 and 2 and Beaver Valley Common Plant, Perry Unit No. 1 and Brunot Island. I show the original cost, book reserve and net book value associated with these plants as reflected in Docket R-870651 in my exhibits.

Q. Was depreciation expense for those plants reflected in that rate case?

A. Yes. I have presented the depreciation expense approved in that case in my exhibits.

Q. Does the Company's claim for stranded costs include any amounts previously disallowed by the Commission as imprudently incurred?

A. No. The Commission did disallow in the Company's last rate case, R-870651, an equity return on the Beaver Valley Unit No. 2. However, the Company subsequently sold and leased back this facility. As the lease is an operating lease for accounting purposes, there is no claim for an equity return on the facility in this filing.

Q. Does the Company's claim for stranded costs include any amount which was not included in the Company's last rate case.

A. Yes. As previously discussed the Company is including Warwick Mine as well as the cold reserved units at Brunot Island and Phillips Power Station in the Company's calculation of rate base. All three of these assets have at some time prior to the enactment of the legislation provided benefits to the Company's customers.

PRO FORMA FINANCIAL DATA

Q. Why is the Company submitting pro forma financial data for a 1996 base year?

A. The Commission's recent restructuring filing requirements direct utilities to file data for a pro forma 1996 base period to enable them to unbundle rates into generation, transmission, and distribution components. In compliance with that directive, Duquesne is submitting Exhibit MKO-1, which sets forth the 1996 data and the adjustments necessary to establish normalized conditions.

Q. What is contained in Exhibit MKO-1?

A. Exhibit MKO-1 contains five sections:

Section A presents basic accounting information as of December 31, 1996 from the Company's books of account, as well as the revenue and expenses for 1996.

Section B identifies the adjusted data relating to Duquesne's rate base as of December 31, 1996, as well as the adjusted revenue and expenses for 1996 for determining the Cost of Service Study.

Section C unbundles the rate base into generation, transmission and distribution, as well as unbundling the adjusted revenue and expenses for 1996 for determining the Cost of Service Study into generation, transmission, and distribution.

Section D identifies necessary adjustments to revenues and expenses.

Section E provides the allocation factors utilized in Section C to unbundle the rate base, as well as the factors utilized in allocating the revenues and expenses into functions, i.e., generation, distribution and transmission.

Q. Please describe the components of Duquesne's net plant at December 31, 1996.

A. The pro forma 1996 net plant is comprised of the original cost of plant in FERC Accounts 301, 302, 303, and 310 through 399, less associated accrued depreciation for the same accounts. General plant and associated depreciation reserve have also been reflected. The foregoing data are set forth in Section C of Exhibit MKO-1 and summarized on Page C-1.

Q. Do any adjustments need to be made to the year-end 1996 data?

A. Yes. Adjustments to plant-in service are being made for certain costs at the Perry Unit No. 1 which had been reclassified within the plant accounts to intangible plant. These costs are specifically related to the Perry Unit No. 1.

Q. Is the Company's plant-in-service balance audited?

A. Yes. Both this Commission and the FERC periodically audit the Company's plant records. In addition, annual audits are performed by the Internal Revenue Service, Pennsylvania Department of Revenue and the Ohio Department of Revenue. The Company's independent accounting firm of Deloitte & Touche issues an opinion on

Duquesne's financial statements. In addition, the Commission's Bureau of Audits is currently reviewing the Company's property records and regulatory assets.

Q. Please describe Duquesne's accumulated deferred tax balance.

A. The accumulated deferred tax balance consists of two components: (1) the traditional deferred taxes associated with accelerated depreciation and (2) deferred federal and state taxes associated with previously flowed through benefits which have yet to reverse.

Q. Please elaborate upon the second component.

A. Starting with the adoption of SFAS No. 109, the Company began maintaining deferred taxes based on the difference in the net investment in plant assets under Duquesne's historic regulatory book accounting methodology and its federal income tax accounting methodology. This included establishing and maintaining deferred tax balances for the previously flowed-through differences. As the Company has requested an opportunity to earn a return on and of the corresponding regulatory asset relating to the second component, the entire deferred tax balance appropriately reduces the company's rate base.

Q. Please describe the Company's rate base claim for deferred taxes on contributions in aid of construction.

A. When the Company receives a contribution in aid of construction, the appropriate plant account is reduced by the contribution, with the accompanying effect on plant-in-service and book depreciation. At the same time, the Company is taxed on the contribution and a deferred tax liability is created. The deferred tax liability is reversed through adjustment to the tax depreciation of the facility over the tax life of the facility. Meanwhile, there is a tax cost associated with the initial tax payment by the Company upon receipt of the contribution. The addition of accumulated deferred taxes on contributions in aid of

construction allows the Company to earn a return on this tax payment for the deferred tax on the contribution in aid of construction less any deferred tax reversal over the facility's tax life.

Q. Please describe the pro forma adjustments that were made to base year (1996) operating and maintenance expense.

A. Two types of pro forma adjustments have been made to the Company's base year data: (1) annualizing adjustments to reflect a full year's impact of known changes and (2) normalizing adjustments to eliminate extraordinary items to reflect normal conditions.

Q. Please elaborate on each of the annualization adjustments included in Exhibit MKO-1, Section D.

A. There were a number of annualizing adjustments made to 1996 base year data, each of which is discussed below:

Full Year Effect of the Present State Tax Adjustment Clause("STAC"). The purpose of this adjustment is to eliminate the effect of a credit that was in effect to refund prior year over-collections. This adjustment is reflected on Page 1, Section D of Exhibit MKO-1.

Annualization for Growth of Customers. The purpose of this adjustment is to adjust the 1996 year-end level of customers to annualize the growth of new customers added during the base year. These adjustments are shown on Page 2, Section D of Exhibit MKO-1.

Annualization of Energy Cost Adjustment Revenue ("ECR"). The Company as part of its sale of Fort Martin Power Plant agreed to cap its fuel clause at 14.7. The purpose of

this adjustment is to reflect this level of revenues associated with fuel being rolled into base rates for a full year. Expenses have been adjusted accordingly. This adjustment is show on Page 3, Section D of Exhibit MKO-1.

Sale of Ft. Martin Power Station. Duquesne sold its interest in the Ft. Martin Power Station on October 31, 1996. Thus, base year expenses were required to be adjusted to reflect the absence of these operating and maintenance expenses going forward. The details of this adjustments are set forth on Page 4, Section D of Exhibit MKO-1.

Wages-Benefits Increase. The purpose of this adjustment, which is set forth on Page 5, Section D of Exhibit MKO-1, is to reflect the full year impact of wage and benefit increase for union and management employees.

Annualization of Depreciation. The amortization of the depreciation accrual consists of three components: (1) the amortization of the book accrual, (2) the full year effect on tax depreciation, and (3) the impact on deferred taxes. The book depreciation is annualized by applying the current accrual rates to the year-end plant balance. The current accrual rate includes the increased depreciation of Duquesne's nuclear power plant as well as increased decommissioning expense in accordance with the Company's agreement with the Commission under the Fort Martin Power Plant sale agreement. Effectively, the annualized 1996 accrual is equal to 1997 depreciation without any capital additions. The tax depreciation is amortized in a similar manner. The base year is adjusted to reflect a full year of tax depreciation on year-end plant. Finally, since the Company normalizes federal and state taxes associated with depreciation, the deferred taxes in the test year

must also be adjusted to reflect the new book and tax depreciation. These adjustments are developed on Pages 6, Section D of Exhibit MKO-1.

Annualization of Amortization. The amortization accrual adjustment consists of three components: (1) an adjustment to reflect the amortization of the Company's regulatory assets,(2) an adjustment for the Beaver Valley Unit No. II lease expense. The purpose--the adjustment for the regulatory asset amortization is to reflect the increased collection required during the transition period, rather than as previously included in rates. The lease expense adjustment reflects an increase in this amortization to mitigate the stranded costs associated with the lease of the Company's nuclear plant. These adjustments are developed on Page 7, Section D of Exhibit MKO-1.

Full Year Effect Benefits of Increase In Base. The purpose of this adjustment is to annualize the Company's benefit expense to reflect the level payable upon previously adjusted salaries. This adjustment is set forth on Page 8, Section D of Exhibit MKO-1.

Q. Please describe the Company's weather normalizing adjustment.

A. The purpose of this adjustment is to reflect the impact of normal weather on the base year data. The adjustment is made for each class of service and based upon the relationship between sales and degree days in the winter and degree hours in the summer. Once the impact on customer consumption is determined, it is multiplied by the average unit revenue for the rate class. In addition to adjusting revenues, expenses equal to the sales change multiplied by the marginal energy cost are deducted, resulting in a pre-tax impact. This adjustment appears on Page 9, Section D of Exhibit MKO-1 .

Q. Are there any other adjustments to the base year data?

A. Yes. The consolidated tax savings adjustment allocates the tax benefits associated with a number of investments which have significant tax benefits. The investments include investments in affordable housing projects, investments in IRC Section 29 gas projects, as well as structured tax leasing investments. This adjustment is necessary to reflect the Company's mitigation of taxes which are included in stranded costs. This adjustment is set forth on Page 10 of Exhibit MKO-1.

Functional Unbundling of Revenues, Expenses, and Rate Base

Q. Please describe how expenses were unbundled into generation, transmission and distribution.

A. As can be seen in Exhibit MKO-1 Section E the vast majority of expenses are directly assignable to their specific function. The FERC System of Accounting provides for specific identification of costs. In addition, Duquesne's general accounting system provides for the capturing of costs by specific function.

Q. Describe how the allocation of costs, other than those directly assignable, were developed.

A. A comprehensive analysis of the cost structure of Duquesne was performed in 1996. The goal of this analysis was to develop the ability to allocate costs to the generation function of the business. Because of the legislation which was being contemplated, the Company had taken the initiative to begin looking at the functional unbundling of its vertically integrated business.

Q. Describe the process on how the allocation factors indicated in Section E of Exhibit MKO-1 were developed.

A. Duquesne engaged Metzler and Associates, as well as Deloitte & Touche to review the functional unbundling of the generation portion of the business. A key part of this project including reviewing and developing allocation factors for non-direct charges.

Each component was reviewed in detail, including what factors influenced the amount of charges any one item derived. The factors which influenced the amount of charges incurred for an item were weighted. Based on which factors most directly influenced the variable aspect of the item, these factors were identified as the allocation factor most appropriate in functional unbundling of the specific charge. This process of identifying factors was developed over a number of weeks and included extensive interviews of various support and corporate administration personnel.

Q. Based upon the analysis, does the Company believe the costs contained in Exhibit MKO-1 are properly unbundled to specific functions?

A. Yes. The allocation of costs is a process which requires the exercise of judgment. Our process of analyzing each cost and reviewing each different allocation factor, by item, is a thorough and reasonable process for developing allocation factors. In addition, our process was guided by consultants who have significant experience in this area.

APPENDIX A ITEMS

Q. Mr. O'Brien, you stated that you are responsible for certain of the items required to be filed with the Company's restructuring filing. Please identify these items.

A. Items A: 2, 3, 4, 5, 6, and 7.

Items B: 1, 2, and 3.

Items C: 1 through 22

Items D: 1 through 22

Items E: 1 through 8

Items F: 1 through 19

Items O: 4, 5, and 6.

Q. Does this conclude your testimony?

A. Yes.

R-00974104

Duquesne Statement No. 4-R

Pittsburgh 12-16-97

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Morgan K. O'Brien

Contents:

Response to Intervenor Testimony Regarding Potential Shut-Down of Generation Facilities

REBUTTAL TESTIMONY OF MORGAN K. O'BRIEN

Q. Please state your name and business address.

A. Morgan K. O'Brien, 411 Seventh Avenue, Pittsburgh, PA 15219.

Q. Have you previously participated in this proceeding?

A. Yes. I submitted direct testimony (Duquesne Statement No. 4) and various supporting exhibits with Duquesne's August 1, 1997 filing. A statement of my qualifications is contained in my direct testimony.

Q. What is the purpose of your rebuttal testimony?

A. I will provide certain data to be incorporated in an analysis by Mr. Clayton examining the ramifications of the potential shut-down of one or more generation facilities. The data that I will provide are operating costs which would not be avoidable by shutting down a generation facility. These costs include: (i) a portion of the general and administrative overheads; (ii) certain property taxes; and (iii) certain other taxes. In addition, I will estimate a likely amount of severance costs which would be incurred by the Company if a generation facility were shut down.

Q. Do you address regulatory asset issues in your rebuttal testimony?

A. No. Regulatory asset issues are addressed in Mr. Clayton's rebuttal testimony.

Q. Please describe the costs included in the general and administrative overhead costs that are included in the allocation to generation facilities.

A. Included in the general and administrative overhead allocation are the following: (i) benefits; (ii) facilities and transportation costs; (iii) corporate security; (iv) treasury; (v) corporate accounting; (vi) legal services; (vii) human resources; (viii) executive officers; (ix) environmental analysis; (x) public affairs; (xii) internal audit; and (xiii) payroll.

Q. Would these costs be avoided by shutting down a generation facility?

A. No. These costs are corporate costs which have been allocated to each generation facility based on the ratio of the direct costs of each facility to the total direct costs of all facilities. Thus, these costs would merely be reallocated to the remaining generation facilities after a facility has been shut down.

Q. Have you estimated any reduction in these overhead allocations if a facility were to be shut down?

A. Yes. I based my estimate upon the principle that with fewer employees to administer, as well as fewer accounting transactions as a direct result of shutting down, a portion of the corporate overhead costs would be reduced. Exhibit MKO-2 provides the quantification of the reduction in corporate overheads.

Q. What portion of the corporate overhead have you estimated to be avoidable if a facility were to be shut down?

A. Based upon the analysis provided in Exhibit MKO-2, approximately 20% of the general and administrative overhead cost would be removed from the Company's cost of operation and would be avoidable if a facility were shut down. The remaining portion of the overheads would continue to be incurred by the Company and would be reallocated to the remaining generation facilities.

Q. What would be the effect on property taxes included in the generation facilities' operating costs if a generation facility were shut down?

A. Property taxes for the Pennsylvania generation facilities would be reduced to zero once the value of the unit was written off the Company's accounting records. However, property taxes on the Ohio generation facilities would continue after the value of the unit was written off the Company's accounting records.

Q. Please describe why there would be a difference in the property tax treatment between the Pennsylvania and Ohio facilities.

A. The different outcomes are due to the differences in the way property taxes are calculated and levied in Pennsylvania and Ohio. Pennsylvania bases property taxes for electric utilities on the book value of the plant. The Ohio

property tax law bases property taxes on an assumed 50% of the original historic cost of the plant, plus the cost of any capital additions. The effect of the Ohio law is that property taxes are levelized over the license period of the nuclear facility located in Ohio. The Company is currently litigating this specific provision of the Ohio law and it is clear based upon the litigation record that the Ohio department of revenue applies the law in this manner.

Q. Are there any other taxes that could be avoided if a generation facility were shut down?

A. Yes. Pennsylvania capital stock taxes are based in part on a revenue factor and in part on a capitalization factor. Writing off the book value of a generation facility would have the effect of decreasing the capitalization component of the tax calculation, but would not affect the revenue component. Based upon the relevant magnitude of each component, 40% of the capital stock tax could be avoided once the book value of the generating facility was written off.

Q. If a generating facility were shut down, would the Company incur incremental costs which have not been included in the Company's projected operating expenses?

A. Yes. The Company would incur incremental severance costs for the employees who would be terminated based upon an administrative decision to shut

down a generating facility. Mr. Duckworth will describe the estimated severance costs the Company would incur if the Perry Unit were shut down. This unit is operated by the joint owners of the facility and would be subject to their specific severance policies. As for the Company-operated facilities, we estimate the severance cost of shutting down the Elrama Units to be $8.0 million and the Cheswick Unit to be $6.0 million.

Q. Please describe how your severance calculations were computed.

A. The Company based these estimates on the severance costs estimated to be incurred in the merger case between the Company and Allegheny Power. In that filing, the Company estimated that it would incur $24 million of severance costs if it reduced its workforce by 500 employees. Reducing that total amount to a cost per employee results in a cost of $48,000 per employee. It is estimated that a shut down of the Elrama unit would reduce the Company's headcount by 160 employees and the Cheswick unit by 120 employees. Simply multiplying the affected employee numbers by the average cost results in the estimate of $8 million at the Elrama Unit and $6 million at the Cheswick Unit.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Q. Thank you.