COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P.O. BOX 3265, HARRISBURG, PA 17105-3265

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JAMES MCNULTY SECRETARY
PA. PUBLIC UTILITY COMMISSION
P. O. BOX 3265
HARRISBURG, PA. 17105-3265

KJR

DOCUMENT
FOLDER

Re: Pennsylvania Public Utility Commission
v.
Duquesne Light Company
Docket No. R-00974104

Dear Secretary McNulty:

Enclosed please find an original and nine (9) copies of the Main Brief of the Office of Trial Staff (OTS) for filing in the above-captioned proceeding. Copies are being served upon all active parties of record.

Sincerely yours,

Kandace F. Melillo

Kandace F. Melillo
Prosecutor
Office of Trial Staff

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c: Honorable John H. Corbett, Jr.,
Parties of Record

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	
DUQUESNE LIGHT COMPANY	:	**Docket No. R-00974104**
(Application to approve restructuring plan pursuant to 66 Pa. C.S. §2806)	:	

MAIN BRIEF OF THE OFFICE OF TRIAL STAFF

Before
Administrative Law Judge
John H. Corbett, Jr.

Kandace F. Melillo
Wayne T. Scott
Prosecutors
Office of Trial Staff

Pennsylvania Public Utility Commission
P. O. Box 3265
Harrisburg, PA 17105-3265
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Dated: February 9, 1998

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I. INTRODUCTION AND SUMMARY OF ARGUMENT

On August 1, 1997, Duquesne Light Company ("Duquesne" or "the Company") filed its stand-alone Restructuring Plan ("Plan") to implement direct access competition pursuant to Section 2806(d) of the Electricity Generation Customer Choice and Competition Act ("Competition Act"), 66 Pa. C.S. §2801 et seq. The Competition Act provides a comprehensive framework for the phase-in to full electric generation competition, as of January 1, 2001.

In accordance with Section 2808(d) of the Competition Act, open evidentiary hearings, including public input hearings, were scheduled and convened by presiding officer Administrative Law Judge John H. Corbett, Jr. (ALJ Corbett). As indicated on the service list attached to ALJ's Corbett Ninth Interim Order, which officially closed the record in this proceeding, about 38 separate parties participated in this proceeding.

The major parties of record, in addition to the Company, include the Office of Trial Staff (OTS), the Office of Consumer Advocate (OCA), the Office of Small Business Advocate (OSBA), the Duquesne Industrial Intervenors (DII), Hospital Shared Services and Administrative Resources, Inc. (HSS/ARI), the City of Pittsburgh (Pittsburgh), Mid Atlantic Power Supply Association (MAPSA), Enron Power Marketing, Inc. (Enron), the Environmentalists, the Pa. Retailers' Association (PRA), David Hughes (a

Duquesne customer representing himself), and the International Brotherhood of Electrical Workers (IBEW).

The record officially closed on January 23, 1998. Main Briefs are due on February 10, 1998, and Reply Briefs (with the exception of the statutory parties' Reply Briefs) are due on February 17, 1998. Due to the state holiday on February 16, 1998, the statutory parties' Reply Briefs (Reply Briefs of OTS, OCA, and OSBA), and the Reply Brief of the City of Pittsburgh are due on February 18, 1998. See, ALJ Corbett's Ninth Interim Order Closing The Record.

OTS submitted the direct testimony of four witnesses in this proceeding: OTS Statement No. 1 and Exhibit No. 1--the direct testimony and exhibit of Eric Van Jeschke concerning fair rate of return and the development of a discount rate for use in OTS' net present value analyses; (2) OTS Statement No. 2 and Exhibit No. 2--the direct testimony and exhibits of Darren D. Gill concerning nuclear and fossil plant decommissioning; (3) OTS Statement No. 3--the direct testimony of Paul M. Yarolin concerning Universal Service and rate unbundling; and OTS Statement No. 4 and Exhibit No. 4--the direct testimony and exhibit of Paul J. Metro concerning valuation and recovery of stranded costs.

OTS also submitted the surrebuttal testimony of two witnesses in this proceeding: OTS Statement No. 2-SR--the surrebuttal testimony of Darren

D. Gill concerning nuclear and fossil plant decommissioning; and (2) OTS Statement No. 4-SR and Exhibit No. 4-SR-- the surrebuttal testimony and exhibit of Paul J. Metro concerning valuation and recovery of stranded costs. In addition, OTS presented six (6) cross-examination exhibits, which were admitted into the record of this proceeding.

To summarize OTS' position, a market-based valuation process is far superior to a one-time administrative determination of stranded generation plant-related costs. This market-based valuation could occur either through a panel of experts, subject to Commission review, or a generation plant auction. OTS supports the Company's proposal to defer the final valuation with two modifications: (1) a possible extension of the CTC and rate cap period to prevent "rate shock" and (2) use of 10.50% for the ROE spill over proposal. These modifications are reasonable and should be adopted.

If a one-time administrative determination is required, then OTS proposes a $1,025.32 million valuation of stranded generation plant, in comparison to the Company's $1,541.68 million. The total OTS stranded cost allowance, including regulatory assets, is $1,378.68 million, in comparison to the Company's $1,898.96 million, based upon the Company's revised numbers as submitted in a fax memo to the ALJ and all parties on February 6, 1998. See also, OTS Ex. No. 4-SR, Sch. 1.

The OTS one-time stranded cost allowance is comprised of the Company's filed values, which are net of taxes, with a net book value reduction of $65.58 million, to disallow stranded cost treatment of the cold reserved units at Phillips and Brunot Island, a net book value reduction of $41.11 million, to disallow M&S and Fuel-Related Sunk Costs, an increase in net book value of $8.95 million for the Present Value of the Beaver Valley 2 Lease Expense (due to differences between the OTS and Duquesne discount rates), a disallowance of $78.8 million in net present value decommissioning expense (due to rejection of contingency factors and recognition that generation customers should also "pay for" decommissioning), a total disallowance of $208.23 million in negative market value associated with PV of Costs Independent of Operation, an increase in estimated market value (decrease in stranded costs) of generating plants by $131.6 million (due to use of the delayed entry market value portfolio), and a $3.92 million disallowance of claimed regulatory assets for deferred caretaker costs associated with the cold reserved units. See, OTS Ex. No. 4-SR, Sch. 1; Main Brief Appendix (Appendix) Tables 1-6.

If a final valuation is delayed until 2003, as supported by OTS, then the above-mentioned disallowances, with the exception of the administrative market value adjustment, should also be reflected, to the extent they are claimed by the Company.

The OTS-recommended return on equity for Duquesne of 10.50% is reasonable, fully supported by the record, and should be accepted. This produces a discount rate of 7.43% for net present value purposes. OTS St. No. 1, p. 8.

Duquesne should be required to unbundle its distribution service charge into metering, billing, a Universal Service and Conservation Fund Charge (separate line item) and drop lines, as supported by OTS witness Paul Yarolin's testimony. In addition, the Universal Service and Conservation Fund Charge should equitably be applied on a customer basis and not a kwh basis and should be applied to customers in all rate schedules. OTS St. No. 3.

II. PHASE-IN OF CUSTOMER CHOICE

This topic was not addressed by OTS in this proceeding.

III. TRANSMISSION AND DISTRIBUTION RATES; UNBUNDLING ISSUES

This topic was not addressed by OTS in this proceeding.

IV. TRANSITION OR STRANDED COSTS

A. Overview of Stranded Cost Valuation and Recovery Approaches

1. Introduction

Pursuant to Sections 2808(a) and 2804(13) of the Public Utility Code, 66 Pa. C.S. §2808(a) and 66 Pa. C.S. §2804(13), electric companies are

provided the opportunity to recover transition or stranded costs, as defined in the Competition Act, through a Competitive Transition Charge (CTC) assessed upon every customer accessing the electric company's transmission and distribution (T & D) network. The Competition Act defines "transition or stranded costs" as follows:

> An electric utility's 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, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the [C]ommission determines will remain following *mitigation by the electric utility*. Emphasis added.

In accordance with the Competition Act, the term "transition or stranded costs" include (1) regulatory assets and other deferred charges typically recoverable under current regulatory practice, the unfunded portion of the utility's projected nuclear generating plant decommissioning costs and cost obligations under contracts with nonutility generating (NUG) projects which have received a Commission Order, the recoverability of which is to be determined pursuant to 66 Pa. C.S. §2808(c)(1); (2) prudently incurred costs related to cancellation, buyout, buydown or renegotiation of NUG projects, subject to statutory conditions, the recoverability of which is to be determined pursuant to 66 Pa. C.S. §2808(c)(2); and (3) net plant investments and costs attributable to the utility's existing generation plants and facilities, and certain

other enumerated costs, the recoverability of which is to be determined pursuant to 66 Pa. C.S. §2808(c)(3).

In OTS' view, the operative words in the statutory stranded cost definition, supra, for purposes of stranded cost valuation, are "known and measurable." The valuation methodology adopted in this proceeding should be the most reasonable means available to quantify, with reasonable accuracy, Duquesne's stranded electric generation-related costs.

2. Duquesne's Approach

In its direct case, Duquesne included a claim for regulatory assets and decommissioning expenses under 66 Pa. C.S. §2808(c)(1). Duquesne St. No. 4, pp. 7-8. Duquesne generally has no NUG project exposure and therefore, stranded costs under 66 Pa. C.S. §2808(c)(2) are not an issue.

With respect to its generation plant-related stranded costs under 66 Pa. C.S. §2808(c)(3), Duquesne proposed, in its direct case, a market-based valuation approach which would generally defer, until 2003, a final valuation of Duquesne's generation plant-related stranded costs, as of December 31, 2005. This is in the latter half of the transition period to full competition (January 1, 1999 to December 31, 2005). Duquesne St. No. 2, p. 2; Duquesne St. No. 3, p. 5. The Company contends that, by this time, a competitive generation market will likely have developed so as to permit a stranded cost determination based upon actual market data. Duquesne St. No. 3, p. 52. According to

Duquesne, only a market-based determination of stranded costs can reasonably satisfy the "known and measurable" criteria set forth in the Competition Act. Administrative determinations, which rely upon market price **projections**, are inherently inferior to valuations based on **actual** market data. Duquesne St. No. 3, pp. 6-7.

This final market valuation in 2003 is proposed to be calculated by a three-member arbitration panel using objective market data such as forward contracts, futures contracts, and/or comparable generating unit asset sales. Duquesne St. No. 1, pp. 14-15. The panel recommendation would be subject to Commission review and the Commission is not bound by the panel's findings on market value. Duquesne St. No. 3, p. 49.

Until the final valuation occurs, Duquesne proposes to set annual CTCs on the basis of an annual Request For Proposal (RFP) to sell a substantial block of power for a one-year term. Customer-specific CTCs will be set using the market prices established by the RFP, information about each customer's consumption and information on class load shapes. Duquesne St. No. 1, p. 17. The CTC, based on these annual RFPs, will collect a pool of dollars that will be compared to the book value of generation-related assets (net of amortization) as of December 31, 2005 in the final valuation process. In the final valuation, the panel will recommend a CTC that will recover any remaining level of stranded costs. If no stranded costs associated with

generating plants exists at that time, there would be no CTC. OTS St. No. 4, p. 11. If stranded costs are projected to extend beyond 2005, given Duquesne's rate cap under Section 2804(4) of the Competition Act, 66 Pa. C.S. §2804(4), Duquesne would propose to extend the rate cap beyond 2005. Duquesne St. No. 2, p. 41.

Duquesne did perform a stranded cost projection based upon a range of costs, solely for the purpose of determining whether it would likely have stranded costs remaining as of the end of the transition period. This determination was required as support for Duquesne's proposal to charge its capped rates through the transition period. See, 66 Pa. C.S. §2804(4)(v); Duquesne St. No. 2, pp. 28-29. Duquesne committed to an amortization and depreciation of at least $1.7 billion in stranded costs during the transition period, through charging its capped rates. Duquesne St. No. 1, p. 5.

Duquesne proposed two mechanisms during the transition period which could trigger an earlier final valuation of stranded costs and an earlier end to the CTC. First, Duquesne states that if market prices rise sufficiently prior to 2003, it is possible that an overrecovery of stranded costs could occur unless safeguards are provided. The Company's proposed solution is to trigger an early market valuation based on established price triggers for the years 2001 and 2002. Duquesne's calculated trigger price in its direct case was $28.5/mwh for the year 2001 and $29.2/mwh for the year 2002. The early

trigger price is that market price that would likely produce a high enough residual value so as to allow an early end to the rate cap and further collection of the CTC. The Company proposed to use the annual RFP solicitation for 2000 and 2001 as market evidence of whether the trigger prices are exceeded. If the market price determined in these solicitations exceeds the values set forth above, the final market-based valuation would be accelerated. Duquesne St. No. 2, p. 41.

The second trigger proposed by Duquesne in its direct case relates to the Company's "ROE spill over" adjustment. As explained by Company witness Donald Clayton, Duquesne proposed to establish a collar on its earnings of plus or minus .5% around its claimed return on equity (ROE) of 11.5%. If the Company's earnings exceed the upper collar of 12%, it would establish a deferred revenue account which would ultimately be used to fund accelerated depreciation and amortization of stranded costs. However, if earnings fell below 11%, an adjustment to the deferred revenue account would be made to increase the Company's earnings to the 11% level or to eliminate the credit and balance in the account, whichever is smaller. If at any time during the transition period, the balance in the deferred revenue credit account, when netted against Duquesne's net book value of generating and regulatory assets, was equal to Duquesne's estimated net book value as of December 31, 2005,

the final market-based valuation would be triggered. Duquesne St. No. 2, p. 42.

In the rebuttal phase of this case, Duquesne modified its original stranded cost valuation proposal in three ways as discussed by Duquesne witness Clayton. First, the Company agreed to provide an option to the Commission[1], **in addition to** the market-based valuation in 2003 described previously, whereby the Commission could order Duquesne to divest its generating assets in 2003 (or sooner if there is an early trigger of the final valuation).[2] This option was offered in response to the positions of several parties that divestiture is the only way to determine a definitive market value for Duquesne's generation assets. Duquesne St. No. 2-R, p. 3.

The Company did not want an immediate generation auction, however, due to concerns about its continuing obligation to serve and its risk, during the transition period, that market prices might rise above the level implicit in the auction price. Duquesne T&D customers might then return to Duquesne as generation customers due to lower generation rates established at

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[1] Since 66 Pa. C.S. §2804(5) precludes the Commission from ordering an involuntary divestiture, Duquesne has framed its divestiture proposal as an agreement by the Company to provide a Commission option for divestiture. Duquesne St. No. 1-R, p. 11.

[2] This divestiture proposal relates to the Duquesne "stand-alone" restructuring and is only being proposed in the event the proposed merger with APS is not consummated. Tr. 178-179.

the time of the auction when market prices were lower. Duquesne would be required to provide generation to these customers within capped rates, regardless of whether Duquesne's market purchases to serve these returning customers was higher. Duquesne St. No. 1-R, p. 14.

Second, the Company agreed in rebuttal to revise its market price trigger, described previously herein, to reflect the OCA market price line. As indicated by Mr. Clayton, this would result in a lowering of the trigger price in 2001 from $28.5/mwh to $24.9/mwh and in 2002 from $29.2/mwh to $25.6/mwh. The Company characterizes this modification as adding conservatism to the Company's stranded cost recovery proposal as it would make an early valuation more likely. Duquesne St. No. 2-R, pp. 3, 6.

Third, the Company eliminated its .5% collar on its 11.5% ROE spill over proposal. This was done in response to criticisms that Duquesne was trying to gain approval of a 12% ROE. Thus, the Company has agreed to record all entries to the deferred revenue account based on an 11.5% ROE. Duquesne St. No. 2-R, pp. 6-7.

Since the Company's position is that final stranded cost valuation should be deferred until 2003, the Company did not propose a one-time administrative valuation of generation plant-related stranded costs in its direct case. OTS St. No. 4-SR, p. 4. However, in rebuttal, in response to OCA and DII's contentions that Duquesne's market valuation proposal is deficient in that

it does not include a one-time quantification of stranded costs as of January 1, 1999, the Company indicated that its evidence supported a total stranded cost determination of $1,916 million, including regulatory assets of $374.45 million. Duquesne St. No. 3-R, pp. 4, 9, 15. The stranded generation plant component of the $1,916 million is $1,542 million, including a first-time claim of approximately $208 million, related to purportedly unavoidable sunk costs incurred regardless of whether plants are operating (PV of Costs Independent of Operation), and approximately $41 million claimed as M&S and Fuel-Related Sunk Costs. Duquesne St. No. 2-R, p. 13-14; Duquesne St. 3-R, p. 11; Duquesne Ex. No. DJC-10.

In a fax memo to the ALJ and all parties dated February 6, 1998, the Company revised its regulatory assets claim downward, so that Duquesne's total one-time quantification of stranded costs as of January 1, 1999, is now $1,898.96 million, including regulatory assets of $357.28 million. The stranded generation plant component of the $1,898.96 million, remains at $1,542 million. See, Appendix, Table 1.

In rejoinder, Duquesne CEO David Marshall testified that the Company was willing to move up the date for the optional asset auction. Instead of the 2003 date for the auction referenced in rebuttal, the Company is now willing, in its stand-alone restructuring case, to agree to an immediate auction, if the Commission determines that it cannot accept Duquesne's auction

offer due to the delay. Duquesne, however, reserved its right to submit a proposal for addressing Duquesne's continuing obligation to serve under the rate cap if and when the Commission orders an immediate auction. Duquesne St. No. 1-Rejoinder, pp. 1-2.

3. Intervenor Approaches

OTS engineer Paul J. Metro presented the OTS position with respect to regulatory assets and generation plant-related stranded costs. OTS St. No. 4. OTS has not opposed the Company's claim for regulatory assets, with the exception of deferred caretaker costs, to be addressed in a later section of this Main Brief. OTS engineer Darren D. Gill addressed the OTS position on decommissioning, which will also be addressed in a later section of this Main Brief.

Mr. Metro supports, with two modifications, the Company's direct case proposal to defer a final valuation of generation plant-related stranded costs until 2003, and to base the valuation on objective market data in 2003 rather than today's projections. OTS St. No. 4, pp. 15-17. In Mr. Metro's opinion, the market value approach is superior to a "regulator-administered approach", such as would be involved in the one-time administrative quantification of stranded costs as of January 1, 1999, sought by DII and the OCA. As stated by Mr. Metro:

> In a regulator administered approach, the projection of market rates over a 30 year period would be necessary to attempt to determine the net present value of the company's stranded costs. The regulator administered approach is not accurate by any account. . . . I believe that any utility's stranded costs claim is in error if it is based on 30 year market rate projections. In my opinion , the utilities will err in their favor in the calculation of the stranded cost. OTS St. No. 4, pp. 15-16.

Mr. Metro provided an exhibit which compared expert market rate projections from, inter alia, PJM-member electric utility restructurings in Pennsylvania. As can be seen from the wide disparity in market rates, the electric utilities cannot even agree to the same market rate within the PJM service territory, wherein, in Mr. Metro's opinion, the market rates should be identical. OTS St. No. 4, p. 17; OTS Ex. No. 4, Sch. 1.

In OTS' view, the Competition Act does not bar the Company's proposal to conduct a final valuation of generation plant-related stranded costs in 2003, at a time when a competitive generation market is likely to be flourishing and sufficient objective market data can be obtained. In fact, the statutory definition of stranded costs invites such deferred approaches due to the requirement that stranded costs be "known and measurable". As indicated previously, a one-time administrative evaluation of stranded costs in this proceeding, as of January 1, 1999, cannot be accurate by any account. OTS St. No. 4, p. 15.

If the "known and measurable" standard must be satisfied now, in this restructuring proceeding, then it is submitted that no electric utility could substantiate any generation plant-related stranded costs at this time, absent an immediate auction. Since the Legislature clearly stated that auctions/divestitures had to be voluntary (66 Pa. C.S. §2804(5)), then, absent an agreement to at least a partial divesture/auction, the generation plant-related stranded cost in all restructurings would have been preordained to be zero, if one interprets the Competition Act as requiring stranded cost levels to be definitively determined now. Given the intent of the Competition Act to provide at least an opportunity for stranded cost recovery (66 Pa. C.S. §2808(a)), this is an absurd result which is not in accord with principles of statutory construction. See, 1 Pa. C.S. §1922 (1); see also, Pa. P.U.C. v. Commonwealth, 23 Pa. Cmwlth. 566, 353 A. 2d 887 (1976). Accordingly, this interpretation should be rejected, in favor of allowing for a delayed valuation in 2003.

OTS does have two modifications to Duquesne's deferred valuation proposal. First, OTS proposes that the rate cap under 66 Pa. C.S. §2804(4) and CTC collection period be extended if the final valuation in 2003 determines a stranded cost level which would produce CTC "rate shock". As indicated by Mr. Metro, it apparently is the Company's intention to begin collecting stranded costs **determined by the panel**, pursuant to the 2003

valuation, **on January 1, 2004**, and to collect these costs over the two remaining transition years. If the valuation at that time results in stranded costs which exceed the upper level of Duquesne's projections of remaining stranded costs (approximately $423 million), then Mr. Metro recommends that the CTC and rate cap period be extended for whatever time is necessary to recover the additional stranded costs at the then current recovery rate. OTS St. No. 4, pp. 13-14; Duquesne Ex. No. DJC-3 (Revised), p. 1; Duquesne St. No. 2, p. 11.

The Competition Act specifically permits extensions to the CTC collection period if ordered by the Commission, for good cause shown. 66 Pa. C.S. §2808(b). Duquesne has filed no testimony in opposition to OTS' rate cap/CTC extension proposal. In fact, Company witness Clayton indicated that the Company would extend the rate cap for CTC recovery beyond 2005.[3] Duquesne St. No. 2, p. 41. Accordingly, this modification should be granted.

The second modification concerns the Company's ROE spill over proposal. Duquesne's position is that 11.5% is a reasonable rate of return on equity and has therefore linked its "ROE spill over" trigger, described

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[3] In Application of PECO Energy Company For Issuance Of A Qualified Rate Order Under Sections 2808 and 2812 of the Public Utility Code, Docket No. R-00973877, Opinion and Qualified Rate Order entered May 22, 1997, at pages 22-25, the Commission apparently questions its authority to direct a utility to extend the rate cap beyond the end of the transition period. However, in the instant case, Duquesne has voluntarily agreed to extend the rate cap.

previously, to 11.5% in earnings. Also, Duquesne originally proposed a .5% collar around the 11.5%, so that, for example, the deferred revenue account would not be triggered until Duquesne's earnings exceeded 12%. However, as will be addressed in a later section of this Main Brief, OTS witness Eric Van Jeschke's testimony established that a reasonable rate of return on equity for Duquesne is 10.50%. OTS St. No. 1, p. 8. Consequently, in his direct testimony, Mr. Metro recommended that 10.50% be used for the "ROE spill over" proposal, with a .5% dead band from 10% to 11%. OTS St. No. 4, p. 14.

However, as indicated supra, the Company modified its ROE spill over proposal in rebuttal to eliminate the .5% dead band. Duquesne St. No. 2-R, pp. 6-7. Accordingly, OTS will also remove the .5% dead band from its recommendation. OTS' proposed modification to 10.5% from the Company's 11.5% is reasonable and fully supported by the testimony of Mr. Jeschke. It should be adopted.

In the event that Duquesne's deferral of final valuation is rejected and the Commission determines that a one-time administrative determination of stranded costs must be done in this proceeding, without benefit of an auction, then OTS proposes a stranded generation plant cost projection of $1,025.32 million, and a total stranded cost of $1,378.68 million, as set forth in OTS Ex. No. 4-SR, Sch. 1, and as revised by Duquesne's February 6, 1998 fax memo.

See also, Appendix, Table 1. The components of this estimate will be separately discussed in later sections of this Main Brief. The Phillips and Brunot Island generating plant disallowance, which reduces net book value of generating plant, and the decommissioning adjustments, each of which is included in OTS Ex. No. 4-SR, Sch. 1, and which are further discussed infra, should also be incorporated in the delayed (2003) panel valuation process.

OTS does not oppose Duquesne's auction/divestiture option, which Duquesne agreed in rebuttal and rejoinder testimony to provide to the Commission.

4. Conclusion

For the reasons stated herein, a market-based valuation process is far superior to a one-time administrative determination of stranded generation plant-related costs. This market-based valuation could occur either through a panel of experts, subject to Commission review, or a generation plant auction. If a one-time administrative determination is required, then OTS proposes a $1,025.32 million valuation of stranded generation plant, in comparison to the Company's $1,541.68 million. See, Appendix, Table 1. The total OTS stranded cost allowance, including regulatory assets, is $1,378.68 million, in comparison to the Company's $1,898.96 million. OTS Ex. No. 4-SR, Sch. 1; Appendix, Table 1; Duquesne February 6 fax memo.

In OTS' view, Duquesne's proposed deferral of the final stranded generation plant-related cost determination until 2003 is not forbidden by the Competition Act, and is consistent with the statutory definition of stranded costs and principles of statutory construction.

OTS supports the Company's proposal to defer the final valuation with two modifications: (1) a possible extension of the CTC and rate cap period to prevent "rate shock" and (2) use of 10.50% for the ROE spill over proposal. These modifications are reasonable and should be adopted.

B. Generation-Related Stranded Costs (Recovery Pursuant to Section 2808(c)(3))

1. Introduction

Section 2808(c)(3) of the Competition Act, 66 Pa. C.S.§2808(c)(3), concerns the recovery of, inter alia, stranded net plant investments and costs attributable to the utility's existing generation plants and facilities. As stated in the previous section, it is OTS' position that, in lieu of an immediate auction, a final valuation of generation plant-related stranded costs should occur in 2003, after the competitive generation market has had the opportunity to develop and sufficient objective market data can be obtained.

However, as will be addressed below, there are stranded plant adjustments which should be made regardless of the timing of valuation. In

addition, as addressed below, there are costs which Duquesne has included in its one-time administrative evaluation analysis which should be disallowed.

2. Net Book Value

(a) Total Net Book Value

The total net book value of Duquesne's fossil generating plants should be reduced by $65.58 million, to reflect a disallowance of the stranded cost claim made by Duquesne with respect to Phillips Power Station (Units 1, 2, 3, and 4) and Brunot Island Power Station (Units 3 and 4). See, Appendix, Table 6.

In addition, if a one-time administrative valuation of stranded costs is required as of January 1, 1999, then the Company's claim for $1,236.95 million in net book value should also be reduced by $41.11 million ($33.40 million nuclear and $7.70 million fossil) for the category "M & S and Fuel-Related Sunk Costs". See, Duquesne Ex. No. DJC-10; Appendix, Tables 5 and 6. This claim was not included in Duquesne's original filing and consequently was not included in the OTS stranded cost valuation allowance, as shown on OTS Ex. No. 4-SR, Sch. 1.

OTS' resulting net book value is $1,139.22 million ($764.14 million nuclear and $375.08 million fossil). OTS Ex. No. 4-SR, Sch. 1; Appendix, Tables 2 and 3.

(b) Treatment of Beaver Valley Lease Costs

OTS included a nuclear stranded cost allowance of $287.19 million for the present value (PV) of the Beaver Valley 2 lease expense. OTS Ex. No. 4-SR, Sch. 1; Appendix, Table 5. This allowance slightly exceeds the $278.24 million claim shown by the Company in Duquesne Ex. No. DJC-10, due to application of the OTS discount rate of 7.43%, which is used to compute present value. OTS St. No. 1, p. 8.

(c) Recovery of Phillips and Brunot Island Costs

Duquesne has included in this filing a fossil plant stranded cost claim of $65.58 million net book value[4] for Units 1, 2, 3, and 4 at Phillips Power Station and Units 3 and 4 at Brunot Island Power Station. Duquesne St. No. 2, p. 33; OTS St. No. 4, p. 24; Tr. 303. All of these units were placed in cold reserve in 1986, as approved by Commission Order entered May 2, 1986, at Docket No. P-860103, with respect to Brunot Island, and by Commission Order entered July 30, 1986, at Docket No. P-860132, with respect to Phillips. Tr. 194-195. These units were removed from rate base in the Company's base rate case in 1987, and have not been returned to service since that time. Tr. 196.

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[4] The $106.8 million claim for the cold reserve units mentioned in Mr. Metro's testimony is the $65.58 million rate base amount plus approximately $40 million in deferred taxes. OTS Cross Ex. 3.

Brunot Island Units 2A and 2B were placed back in service in 1996 as a result of the Ft. Martin agreement, but these units are not included within the $65.58 million net book value claim for the cold reserved units. Tr. 196, 303. The Company presently has no plans to place its cold reserved units back into service. Tr. 201.

OTS witness Metro presented testimony in opposition to the inclusion of the Phillips and Brunot Island cold reserved units in the Company's stranded cost claim. OTS St. No. 4, pp. 23-25. Mr. Metro's position is fully in accord with the Competition Act and its definition of stranded costs, while the Company's position in inconsistent with the Competition Act.

As stated in 66 Pa. C.S. §2803, the definition section, "stranded costs" must be costs that are traditionally recoverable under a regulated environment. Costs for generating plants that are not "used and useful" are not traditionally recoverable under a regulated environment[5]. While the Competition Act at 66 Pa. C.S. §2803 provides an exception for costs attributable to physical plants no longer used and useful because of the transition to retail competition, Duquesne witness Clayton acknowledged that these units were placed in cold reserve and removed from rate base at a time when there was no competitive electric generation market for Duquesne's end

[5] See, e.g., Barasch v. Pa. P.U.C., 516 Pa. 142, 169-170, 532 A. 2d 325, 338-339 (1987), aff'd, 488 U.S. 299, 109 S.Ct. 609 (1989).

use customers. Tr. 195-196. Furthermore, the Company does not deny the possibility that excess capacity played a role in the decision to "cold reserve" these units. Tr. 23, 110.

As stated by the Commission in Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code and Joint Petition for Partial Settlement, Docket No. R-00973953, Opinion and Order entered December 23, 1997 (PECO Restructuring Order), pp. 67-68 (Petition for Review filed in Commonwealth Court), Duquesne has the burden to prove, by substantial evidence, that its stranded costs claim is within the statutory definition of stranded costs. As held by the Pa. Supreme Court in Burleson v. Pa. P.U.C., 501 Pa. 433, 437, 461 A. 2d 1234, 1236 (1983), when a party bears the burden of proof, that party must, in addition to establishing a prima facie case, establish that:

> . . .the elements of that cause of action are proven with substantial evidence which enables the party asserting the cause of action to prevail, precluding all reasonable inferences to the contrary.

Clearly, Duquesne has not met its burden of proving that the costs relating to its cold reserved units are traditionally recoverable under a regulated environment or that these costs are attributable to plants no longer used and useful **because** of the transition to retail competition. Accordingly, Duquesne's

stranded cost claim ($106.8 million including deferred taxes, of which $65.58 million is the rate base amount) for the cold reserved units should be rejected.

(d) Conclusion

For all the reasons previously stated, Duquesne's claim for stranded costs relating to the cold reserved units should be rejected. In addition, Duquesne's claim of $41.11 million for M & S and Fuel-Related Sunk Costs should be rejected. The resulting net book value of stranded generating plant is $1,139.22 million. Appendix, Tables 2, 3, 5, and 6.

3. Market Value

(a) Introduction

As stated by Duquesne witness Michael Schnitzer, it is the difference between net book value, addressed in the previous section, and competitive market value which represents that portion of book value stranded by competitive retail access. The competitive market value of electric generation plant is what a willing buyer would pay for the right to receive the net after-tax cash flows from the plant in the future. The level of after-tax cash flows is largely dependent upon the prevailing market price for power. Duquesne St. No. 3, p. 7.

In its direct case, the Company did not propose a specific market value of its generation plant, as of January 1, 1999, as its approach, supported by the OTS, is to defer final valuation until 2003. However, in rebuttal, in

response to criticisms of the OCA and DII, the Company stated that if a one-time administrative quantification was required, its best estimate of generation plant market value, as of January 1, 1999, is $27 million, which results in total stranded costs of $1,916 million, subsequently revised on February 6, 1998, to $1,898.96 million. Duquesne St. No. 3-R, p. 4; Duquesne St. No. 2-R, p. 12; Duquesne Ex. No. DJC-20, p. 1; Duquesne February 6 fax memo.

The Company's $27 million estimate assumes the low end of market value for Duquesne's generating plants, based upon Duquesne witness Michael Schnitzer's market price analysis and the results of the Company's 1997 solicitation to sell firm power. Duquesne St. No. 2-R, p. 12. There is an inverse relationship between generating plant market values and stranded costs; i.e., as market value decreases, stranded costs increase. Tr. 395-396.

OTS witness Paul Metro presented the OTS position on market value, assuming that a one-time administrative determination of stranded costs is required in this proceeding. Mr. Metro used the Company's market price study, but supports a plant margin determined under the Company's delayed entry portfolio. This is the plant margin result which falls between the Company-supported low market price scenario and the high market price scenario. OTS St. No. 4-SR, p. 5. Use of this portfolio accommodates Mr. Metro's assessment that utilities err on the high side with respect to stranded costs (therefore, Duquesne supports low market prices) and that the mid-range

portfolio is more likely to be closer to the average of most market price projections. The resulting market value is $159 million ($81.10 million nuclear and $77.90 million fossil), as shown on OTS Ex. No. 4-SR, Sch. 1; see also, Appendix, Tables 2 and 3. Further discussion of the delayed entry portfolio follows.

(b) Market Price Projections

(i) Forecasting Methodology

As indicated previously, OTS agrees with the Company's assessment that market price forecasts are inherently inferior to use of actual market prices for determining market value. However, if a one-time administrative determination of stranded costs is required as of January 1, 1999, then market price projections must be used to determine market value, to be netted against net book value for determining stranded generation plant costs.

OTS accepts the Company's market price forecasting methodology, but recommends use of the delayed entry portfolio of market prices.

(ii) Input Assumptions

The delayed entry portfolio assumes that new combined cycle capacity will not become economic until after the year 2006. Duquesne St. No. 3, p. 35. As indicated by Mr. Metro, this is a reasonable assumption as it

is unlikely that new combined cycle capacity would be economic to build in 2006 based on the 1997 RFP results, particularly if the required new entry prices are at the high end of the range projected by Duquesne. OTS St. No. 4-SR, p. 6.

(iii) Results

The results of using the delayed entry portfolio is that generation market value increases from the Company's estimate of $27 million to $159 million and stranded costs are reduced by $132 million (159 - 27 = 132). Duquesne Ex. No. DJC-20, p. 1. See, Appendix, Tables 2 and 3).

(c) Other Evidence of Market Value

This topic was not addressed by OTS.

(d) Conclusion

The Company's delayed entry portfolio should be used to determine the market value of Duquesne's generation plants, if a one-time administrative evaluation as of January 1, 1999, is required. This portfolio provides for a plant margin between the low and high market value portfolios, which provides for a fair and balanced estimation of the market rate. The assumption that new combined cycle capacity would become economic after 2006 is reasonable and supported by the record.

However, OTS continues to favor a deferral of generation plant valuation until 2003, unless an immediate auction is held. Actual market prices

are far superior to projections in terms of accuracy--which is a stranded cost requirement under 66 Pa. C.S. §2803 (definition of stranded cost).

4. Other Factors Affecting Market Value/Stranded Costs

(a) Life Extension

This topic was not addressed by OTS.

(b) Plant Shutdowns

This topic was not addressed by OTS.

(c) Productivity Gains

This topic was not addressed by OTS.

(d) Costs Independent of Operation

This $208.23 million present value claim ($95.61 million nuclear and $112.62 million fossil) was first presented by the Company in rebuttal in its one-time administrative valuation alternative. Duquesne St. No. 2-R, p. 14. OTS did not specifically address this issue in testimony due to time constraints; however, this issue was addressed by OCA witness Matthew Kahal.

According to Mr. Kahal, this claim assumes that stranded cost quantification should incorporate negative market values for generating units. This is a change from the Company's direct case where negative market values (except for decommissioning) were set to zero. Mr. Kahal indicates that the Company's claim is not supported by discussion, analysis, or presentation. OCA St. No. 1A, pp. 10-11.

OTS witness Metro did not include an allowance for PV of Costs Independent of Operation in the Summary of OTS Stranded Cost Estimates, provided in OTS Ex. No. 4-SR, Sch. 1. See also, Appendix, Tables 2 and 3. This is the summary of OTS' position on stranded cost valuation, as modified by the Company's February 6, 1998, fax, in the event the Commission requires a one-time administrative determination of stranded costs as of January 1, 1999, in this proceeding.

(e) Projected Capital Additions and O & M Expense

This topic was not addressed by OTS.

(f) Environmental Regulations

This topic was not addressed by OTS.

(g) Other

Other issues in this category were not addressed by OTS.

(h) Conclusion

The only issue addressed/or and disallowed under this subsection of the Main Brief was PV of Costs Independent of Operation (see above).

5. Conclusion

In conclusion, costs related to Duquesne's cold reserved units should be disallowed as stranded costs in this restructuring proceeding.

If a one-time, administrative determination of stranded costs is required in this proceeding, OTS recommends that market value be established

using Duquesne's delayed entry market price scenario. Duquesne's claimed PV of Costs Independent of Operation should not be allowed. In addition, Duquesne's claim of $41.11 million for M & S and Fuel-Related Sunk Costs should be rejected.

C. Merger Savings

This topic was not addressed by OTS in this stand-alone restructuring proceeding. It is addressed by OTS in the merger docket.

D. Decommissioning

1. Nuclear Decommissioning

Nuclear decommissioning is the dismantlement, decontamination, removal and disposal of the components of a nuclear generating facility at the end of its useful life. Duquesne has claimed a share of the decommissioning responsibility for the Beaver Valley 1 and 2 and the Perry nuclear sites in its stranded cost claim. OTS St. No. 2, pp. 2-3.

Duquesne's estimate for the decommissioning of Beaver Valley 1 and 2 is $727.7 million and its estimate for Perry is $650 million, for a total of approximately $1,378 million (1997 dollars). Duquesne St. No. 13, p. 4; OTS St. No. 2, p. 4; OTS Cross Ex. 2. Based on Duquesne's partial ownership share in these nuclear sites, the Company's share of estimated nuclear decommissioning expenses is $307.7 million. OTS St. No. 2, p. 4. This estimate is based upon site-specific studies performed by Duquesne consultant

Thomas LaGuardia. Duquesne St. No. 4, p. 17. Mr. LaGuardia also included contingency factors of 21.7% for Beaver Valley 1, 21.74% for Beaver Valley 2, and 16.71% for Perry, which he added to his underlying estimates. OTS Cross Ex. 2; OTS St. No. 2, p. 4. Duquesne's stranded costs claim related to the $307.7 million estimate is $57.40 million. Duquesne Ex. No. DJC-20, p. 2.

Funds for nuclear plant decommissioning are currently being recovered in Duquesne's rates and are deposited in an external nuclear decommissioning trust fund, as required by Nuclear Regulatory Commission (NRC) regulations and applicable Commission Orders. Duquesne St. No. 4, p. 16. Duquesne proposes to continue to recover nuclear decommissioning expenses at the current level of approximately $9 million per year through its CTC until January 1, 2006. Duquesne St. No. 4, p. 17; Tr. 592. At that time, the Company is proposing to treat any remaining unfunded balance as a reduction in any residual value of its generation plant, that would enter into the final valuation proposed by the Company to be deferred until 2003. Duquesne St. No. 4, p. 17.

OTS engineer Darren Gill presented the OTS position in opposition to the Company's nuclear decommissioning claim and method of recovery. As stated by Mr. Gill, the Company's $1,378 million estimate, which includes a 4% annual inflation factor up to the year of each plant's

decommissioning, is improperly inflated again due to the inclusion of contingency factors ranging from 16.7% (Perry) to 21.74% (Beaver Valley 2). OTS St. No. 4, pp. 4-5; Duquesne St. No. 2, p. 35.

Mr. Gill's opposition to contingency factors is in accord with the Competition Act, which provides that claimed stranded costs must be "known and measurable." 66 Pa. C.S. §2803. As acknowledged by Mr. LaGuardia, the contingency factor was added "to allow for the effect of unpredictable program problems on costs." Duquesne St. No. 13, p. 15. There is simply no way that unpredictable program problems can produce "known and measurable" costs, and therefore, Duquesne has not met its burden of proof. Also, while Mr. LaGuardia provided a list of the types of problems which he agreed may occur in decommissioning a nuclear unit and which are covered by the contingency, he admitted that the level of these costs was not known. Duquesne St. No. 13, pp. 22-23; Tr. 649-653.

In Pa. P.U.C. v. Pennsylvania Power & Light Company, 85 Pa. P.U.C. 306 (1995), the Commission explicitly rejected a similar contingency factor proposed by Mr. LaGuardia in site-specific decommissioning studies for PP&L.[6] The Commission characterized the contingency factor as "little more

[6] In the PECO Restructuring Order, supra, contingency factors were not explicitly addressed in the Commission decision to approve PECO's nuclear decommissioning approach.

than estimates of what may occur in estimates of decommissioning cost claims." 85 Pa. P.U.C at 344. Thus, the contingency factor was disallowed due to its speculative nature.

In rebuttal to Mr. Gill, Mr. LaGuardia claimed that contingencies are not an inflation of costs but "a recognition of actual costs incurred in recent experience with decommissioning activities that were not foreseeable in advance." Duquesne St. No. 13-R, p. 11. Mr. LaGuardia is incorrect. As indicated by Mr. Gill in surrebuttal, the costs referenced by Mr. LaGuardia as reflective of contingency costs have already been included in each line item of Mr. LaGuardia's study. Increasing decommissioning estimates above reasonably "known and measurable" levels included in the line items, as Mr. LaGuardia has done with the contingency factor, is an improper inflation of costs and should not be permitted. OTS St. No. 2-SR, p. 3.

The effect of removal of the contingency factors from the Company's total nuclear decommissioning estimate is a reduction of $222.9 million. Based on Duquesne's partial ownership share in Beaver Valley 1 and 2 and Perry, the Company's share of total estimated nuclear decommissioning expenses should be $255.9 million in 1997 dollars. OTS Ex. No. 2, Sch. 1.

OTS witness Gill also disagreed with Duquesne's proposed methodology for recovering nuclear decommissioning costs. As stated previously, Duquesne intends to continue to collect the current level of

decommissioning funding included in rates through the transition period. At the end of the transition period (end of 2005), the Company proposes to treat any remaining unfunded balance as a reduction in any residual value of its generation plant, that would enter into the final valuation proposed by the Company to be deferred until 2003. Duquesne St. No. 4, p. 17. However, if the residual balance of the nuclear generation plant is negative at January 1, 2006, before the Company deducts the unfunded nuclear decommissioning from the plant valuation, the Company reserved the right to extend the CTC beyond 2005 to collect the unfunded portion. OTS Cross Ex. 4.

The Company acknowledged that by January 1, 2006, its nuclear generating plants could be generating power which is sold to retail customers outside of Duquesne's service territory. Tr. 596. In addition, the Company agreed that by January 1, 2006, some portion or even all of Duquesne's customers could be buying generation from sources other than Duquesne but could still be Duquesne distribution customers. Tr. 594. Under these circumstances, if recovery of nuclear decommissioning is permitted to continue to be collected through the CTC, then, as acknowledged by the Company, Duquesne's distribution customers would be paying the entire nuclear decommissioning costs but may not be buying generation from these plants. On the other hand, Duquesne's generation customers (who are actually receiving

power from these plants) are paying nothing towards decommissioning (unless they are also distribution customers). OTS Cross Ex. 6.

Mr. Gill's recovery recommendation would remedy this recovery inequity wherein all nuclear decommissioning costs are allocated to current regulated customers and none are allocated to deregulated generation customers. OTS St. No. 2, pp. 7-8. Mr. Gill accomplished this by first removing all nuclear plant decommissioning costs from Duquesne's market value analysis. He then inflated the OTS 1997 estimate of Duquesne's decommissioning costs ($255.9 million) by the Company's 4% inflation rate for each nuclear unit to arrive at the decommissioning expense for each plant in 1998 dollars. See, OTS Ex. No. 2, Sch. 2, column 2. Next, Mr. Gill performed a net present value (NPV) analysis of the decommissioning expense by first escalating the decommissioning expense for each plant by a 4% annual inflation factor for each remaining year of that plant's operating life, and then by discounting that value each year by the Company's nuclear decommissioning discount rate of 7.5%. OTS St. No. 2, p. 9; OTS Ex. No. 2, Sch. 2; Duquesne St. No. 2, p. 35. This produced a NPV for each plant's decommissioning expense in 1998 dollars, and a total NPV decommissioning expense of about $130.1 million.

Mr. Gill then derived an in-service ratio for each nuclear unit as of December 31, 1998, which represents the percentage of that plant's operating life, using the Company's operating lives, which was dedicated solely

to providing generation service to Duquesne's regulated customers. See, OTS Ex. No. 2, Sch. 2, column 4. This in-service ratio was then applied to the net present valued decommissioning costs for each plant to derive a total combined nuclear decommissioning recovery level of $61.327 million, to be recovered from regulated customers through the CTC.[7]

However, as indicated in Duquesne Ex. No. DJC-7 (revised), the decommissioning fund has $57.840 million at December 31, 1998. Thus, current ratepayers should only be responsible for the difference between the $61.327 million and the $57.840 million that current ratepayers have already contributed to the fund, for a balance of $3.487 million (rounded to $3.5 million in Appendix, Table 2) to be included in the CTC for recovery. The remaining dollars needed to fund nuclear decommissioning, which OTS estimates as the difference between the $130.1 million NPV of decommissioning expense and the $61.327 million current ratepayer share or about $68.773 million, should be recovered from the competitive market, with annual payments over the lives of the plants deposited into a qualified trust fund. OTS St. No. 2, pp. 9, 19; OTS Ex. No. 2, Sch. 2.

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[7] In the PECO Restructuring Order, supra, at page 78, the Commission agreed with PECO's basic premise, which is also Mr. Gill's position, that current ratepayers should only be responsible to fund that portion of nuclear decommissioning expense which is associated with the period of time that the plants provided service solely to regulated customers. The Commission eventually adopted an annuity approach.

In the Appendix attached to this Main Brief, Table 2, the amount of OTS "disallowance" is shown to be $53.90 million, which is a "fallout" number for illustrative purposes. The $3.5 million OTS allowance, which is net of existing funding, is based upon Mr. Gill's "bottoms up" approach of building up to an appropriate nuclear decommissioning stranded cost allowance.

In conclusion, for all the reasons set forth herein, Mr. Gill's recommended nuclear decommissioning expense allowance and recovery methodology for regulated customers should be approved and the Company's proposal should be rejected.

2. Fossil Decommissioning

Fossil decommissioning (referred to as non-nuclear decommissioning in OTS witness Gill's testimony) is the dismantlement, removal and disposal of the components of a non-nuclear generating facility at the end of its useful life. OTS St. No. 2, p. 10. Unlike nuclear decommissioning expenses, the Company's fossil decommissioning expenses have not been funded. Duquesne St. No. 4, p. 18.

Duquesne's estimate of fossil decommissioning is $274.4 million (1997 dollars). This estimate is based upon site-specific studies performed by Duquesne consultant Thomas LaGuardia. Duquesne St. No. 4, p. 19; Duquesne St. No. 13, p. 4. Mr. LaGuardia included a contingency factor of approximately 15%, which was added to his underlying estimates. Tr. 648-

649. Duquesne's stranded costs claim related to the $274.4 million estimate is $66.5 million at December 31, 1998. Duquesne Ex. No. DJC-20, p. 2.

The Company is not proposing to collect any of this $66.5 million through the CTC during the transition period. Tr. 592. Instead, the Company proposes to treat the unfunded balance as a reduction in any residual value of the generation stations as of January 1, 2006, that would enter into the final valuation proposed by the Company to be deferred until 2003. Duquesne St. No. 4, p. 4.

OTS engineer Darren Gill presented the OTS position in opposition to the Company's fossil decommissioning claim and method of recovery. As stated by Mr. Gill, the Company's $274.4 million estimate, which includes a 2.5% annual inflation factor up to the year of each plant's decommissioning, is improperly inflated again due to the addition of a contingency factor of approximately 15%. OTS St. No. 4, pp. 11-12; Duquesne St. No. 2, p. 35; see also, OCA St. No. 3, pp. 20-21.

The arguments against inclusion of Duquesne's contingencies for nuclear decommissioning are also largely applicable to Duquesne's inclusion of contingencies for fossil decommissioning. As stated previously, Mr. Gill's opposition to contingency factors is in accord with the Competition Act, which provides that claimed stranded costs must be "known and measurable." 66 Pa. C.S. §2803. As acknowledged by Mr. LaGuardia, the contingency factor was

added "to allow for the effect of unpredictable program problems on costs." Duquesne St. No. 13, p. 15. There is simply no way that unpredictable program problems can produce "known and measurable" costs. In fact, Mr. LaGuardia admitted that the level of these costs was not known. Duquesne St. No. 13, pp. 22-23; Tr. 649-653.

In addition, the Commission explicitly rejected a request of PP&L to include a similar contingency factor in its decommissioning claim due to its speculative nature. See, Pa. P.U.C. v. Pennsylvania Power & Light Company, supra, 85 Pa. P.U.C. at 344. The Commission also rejected PECO's entire fossil decommissioning stranded cost claim in the PECO Restructuring Order, supra, pp. 91-92.

In conclusion, an increase in decommissioning estimates through contingency factors, as Mr. LaGuardia has done, is clearly an improper inflation of costs and should be rejected. OTS St. No. 2-SR, p. 3. The effect of removal of the contingency factor from the Company's total fossil decommissioning expense estimate of $274.4 million in 1997 dollars is $41.6 million, for a total remaining decommissioning expense estimate of $232.8 million. See, OTS Ex. No. 2, Sch. 3.

OTS witness Gill also disagreed with Duquesne's proposed method for recovery of estimated fossil decommissioning costs. As stated previously, Duquesne proposes to treat the unfunded fossil decommissioning

expense as a reduction in any residual value of the generating stations as of January 1, 2006, that would enter into the final valuation proposed by the Company to be deferred until 2003. Duquesne St. No. 4, p. 4; Tr. 592. However, if the residual balance of generation plant is negative at January 1, 2006, before the Company deducts the unfunded fossil decommissioning from the plant valuation, the Company reserved the right to extend the CTC beyond 2005 to collect the unfunded portion. OTS Cross Ex. 4.

By January 1, 2006, the Company acknowledged that its generating plants could be generating power which is sold to retail customers outside of Duquesne's service territory. In addition, the Company agreed that by January 1, 2006, some portion or even all of Duquesne's customers could be buying generation from sources other than Duquesne but could still be Duquesne's distribution customers. Tr. 594. Under these circumstances, if recovery of fossil decommissioning is permitted to occur through extension of the CTC, as Duquesne said it could request, then, as acknowledged by the Company, Duquesne's distribution customers would be paying the entire fossil decommissioning costs but may not be buying generation from these plants. On the other hand, Duquesne's generation customers (who are actually receiving power from these plants) are paying nothing towards decommissioning (unless they are also distribution customers). OTS Cross Ex. 6.

Mr. Gill's recovery recommendation would remedy this recovery inequity wherein all fossil decommissioning costs are allocated to current regulated customers and none are allocated to deregulated generation customers. OTS St. No. 2, p. 14. Mr. Gill accomplished this by first removing all fossil plant decommissioning costs from Duquesne's market value analysis. He then performed a net present value (NPV) analysis of the Company's $274.4 million estimate by applying the Company's annual inflation factor of 2.5% to each remaining year of the plant service lives and then reducing the value each year by the OTS 7.43% discount rate to derive a total fossil decommissioning estimate (total of all fossil plants), net present valued at January 1, 1999, dollars, of $67.843 million. OTS St. No. 2, p. 16; OTS Ex. No. 2, Sch. 4 and Sch. 5; Duquesne St. No. 2, p. 35.

Mr. Gill then removed the 15% contingency from each plant's decommissioning estimate amount, as shown on OTS Ex. No. 2, Sch. 5. The result is the amount OTS believes it will cost to decommission each plant (total NPV of $57.609 million). Mr. Gill then derived an in-service ratio for each fossil plant as of January 1, 1999, which represents the percentage of that plant's service life, using the Company's service lives, which was dedicated solely to providing service to Duquesne's regulated customers. See, OTS Ex. No. 2, Sch. 5, column 4. The in-service percentage ratio for each plant was then applied to the net present valued decommissioning costs for each plant to

derive a total fossil decommissioning recovery level of $41.605 million, to be recovered from regulated customers through the CTC. The balance of decommissioning costs (i.e., the difference between the $57.609 million and the $41.605 million or about $16 million) should be recovered from the competitive generation market. OTS St. No. 2, pp. 14-16, 19.

In the Appendix to this Main Brief, Table 3, the amount of "disallowance" is shown to be $24.9 million, which is a "fallout" number for illustrative purposes. The $41.6 million OTS "allowance", as shown in the Appendix, Table 3, is based on Mr. Gill's "bottoms up" approach of building up to a proper fossil decommissioning expense stranded cost allowance.

In addition, Mr. Gill recommended that Duquesne be required to place all funds received for fossil plant decommissioning into a non-qualified trust fund. As stated by Mr. Gill, and not refuted by the Company, requiring the Company to place all funds received for fossil decommissioning into a non-qualified trust is the only means to ensure that funds contributed for decommissioning will be available at the time the plants are actually decommissioned. Otherwise, the Company could use the funds for any purpose and the funds may not be available when needed. If this occurs, funds that have already been provided by ratepayers will have to be duplicated by future taxpayers in the event the federal government or other entity is required to perform the decommissioning. OTS St. No. 2, pp. 17-18.

Mr. Gill's fossil decommissioning funding recommendation is reasonable and should be adopted. Also, for all the reasons set forth herein, Mr. Gill's recommended fossil decommissioning amount and recovery methodology for regulated customers should be approved and the Company's proposal should be rejected.

E. Regulatory Assets and Liabilities

1. Introduction

As stated previously, a utility is permitted to include, in its stranded cost claim, regulatory assets and other deferred charges typically recoverable under current regulatory practice. 66 Pa. C.S. §2803. Duquesne has included a $3.92 million claim, net of taxes, for deferred caretaker costs associated with the cold reserved units as a regulatory asset. See, Duquesne Ex. No. DJC-10, p. 1. This claim should be disallowed for the reasons addressed below in Section 2(g).

2. Disputes Regarding Specific Claims

(a) SFAS 109 Deferred Taxes

This is not an OTS issue.

(b) Unamortized Debt Costs

This is not an OTS issue.

(c) Unamortized Sale/Leaseback Premiums

This is not an OTS issue.

(d) Deferred Rate Synchronization Costs

This is not an OTS issue.

(e) Deferred Employee Costs

This is not an OTS issue.

(f) Deferred Coal Costs

This is not an OTS issue.

(g) Deferred Caretaker Costs

In its claim for regulatory assets, Duquesne has included a claim for deferred caretaker costs associated with the cold reserved units (Phillips and Brunot Island units 3 and 4). Duquesne St. No. 4, p. 14. While the total stranded cost claim is apparently $6.72 million, the claim, net of taxes, is $3.92 million. See, OTS St. No. 4, p. 21; Appendix, Table 4.

OTS engineer Paul Metro presented the OTS position in opposition to this claim. The Company's apparent basis for the claim is that the Commission provided for recovery of these costs in its approval of a Duquesne Petition at Docket No. P-900485 **when the Phillips cold reserved units returned to commercial operation**. See, Affiliated Interest Agreement Between Metropolitan Edison Company, Pennsylvania Electric Company and Jersey Central Power and Light Company; Petition of Duquesne Light Company for Declaratory Order; Petition of Metropolitan Edison Company and

Pennsylvania Electric Company for Declaratory Order, 76 Pa. P.U.C. 281, 308, 332 (1992).

However, the Phillips Power Station never returned to commercial operation. As stated by Mr. Metro, since these plants will not be used to meet the future needs of Duquesne's regulated customers, there is no benefit to ratepayers associated with the preservation costs and Duquesne should not be permitted to recover these preservation costs from customers. OTS St. No. 4, p. 23.

Mr. Metro's position is consistent with the Competition Act, which only provides for recovery of regulatory assets that are "typically recoverable under current regulatory practice." 66 Pa. C.S. §2803. These deferred caretaker costs are not typically recoverable. As stated by the Pennsylvania Supreme Court in Barasch v. Pa. P.U.C., supra, 532 A.2d at 337, "the only expenses which a public utility in this state may recover from ratepayers, through rates, are those expenses which represent the actual costs of providing present public utility service."

These deferred caretaker costs are preservation costs related to the cold reserved units, which are not providing present public utility service. Also, as stated previously, the fact that the cold reserved units are no longer used and useful is not due to the transition to retail competition. Duquesne has

clearly failed to meet its burden of proof that these costs are recoverable under the Competition Act, and its claim should therefore be denied.

As indicated in the Appendix, Table 4, the Company's stranded cost claim of $3.92 million, after taxes, related to deferred caretaker costs, has been removed in the OTS Adjustments column. The total OTS regulatory asset stranded cost allowance is $353.36 million, as revised per the Company's February 6 fax memo.

(h) Pre-Accrual of Nuclear Outages

This is not an OTS issue.

(i) Transition Costs

This is not an OTS issue.

(j) SFAS 106 Deferred Costs

This is not an OTS issue.

(k) Warwick Mine Costs

This is not an OTS issue.

(l) Pilot Program/Customer Education Expense

This is not an OTS issue.

(m) Compensated Absences

This is not an OTS issue.

(n) Injuries/Damages

This is not an OTS issue.

(o) Other

This is not an OTS issue.

3. Conclusion

For the reasons previously stated herein, Duquesne's claim for deferred caretaker costs should be rejected.

F. Recovery of Stranded Costs

1. Introduction

The OTS position on recovery of stranded costs related to decommissioning expense was addressed in the Nuclear Decommissioning and Fossil Decommissioning sections of this Main Brief. In addition, OTS' proposal to extend the rate cap and CTC collection period if CTC "rate shock" would otherwise result from the deferred 2003 valuation, and OTS' proposal to modify Duquesne's "ROE spill over" proposal by substituting Mr. Jeschke's 10.50% ROE as a benchmark, was addressed in Section IV.A.3. of this Main Brief, supra. OTS did not take any additional positions, other than the above-mentioned proposals, with respect to recovery of stranded costs.

2. Proposals to Adjust the Level of Stranded Cost Recovery

(a) Mitigation

This topic was not addressed by OTS.

(b) Sharing of Stranded Costs (OCA and DII)

This topic was not addressed by OTS.

(c) Securitization

This topic was not addressed by OTS.

3. Methods of Stranded Cost Recovery

(a) Accelerated Amortization Under Section 2804(4)(v) (Duquesne's ROE Spillover Proposal)

OTS previously addressed the Company's ROE spillover proposal in Section IV. A.3. of this Main Brief. As indicated therein, OTS does not oppose the Company's ROE spillover proposal, with one exception. For the reasons stated in Section VI of this Main Brief, Mr. Jeschke's 10.50% ROE should be substituted for Duquesne's 11.5% ROE in the Company's ROE spill over proposal.

(b) Immediate Rate Reductions (OCA Proposals)

This proposal was not addressed by OTS.

(c) Rate Cap/CTC Extension

OTS also addressed the rate cap/CTC extension topic in Section IV.A.3. of this Main Brief. As indicated therein, OTS proposes that the rate cap under 66 Pa. C.S. §2804(4) and CTC collection period be extended if the final valuation in 2003 determines a stranded cost level which would produce "rate shock". It apparently is the Company's intention to begin collecting stranded costs determined by the panel, pursuant to the 2003 valuation, on January 1, 2004, and to collect these costs over the two remaining transition

years. If the valuation results in stranded costs which exceed the upper level of Duquesne's projections (approximately $423 million), then Mr. Metro recommends that the CTC and rate cap period be extended for whatever time is necessary to recover the additional stranded costs at the then current recovery rate. OTS St. No. 4, pp. 13-14; Duquesne Ex. No. DJC-3 (Revised), p. 1; Duquesne St. No. 2, p. 11.

The Competition Act specifically permits extensions to the CTC collection period if ordered by the Commission, for good cause shown.. 66 Pa. C.S. §2808(b). Duquesne has filed no testimony in opposition to OTS' rate cap/CTC extension proposal. Accordingly, this modification should be granted.

(d) Other Proposals

None.

4. Other Arguments Regarding Recovery of Stranded Costs

None.

5. Conclusion

The OTS stranded cost recovery proposals with respect to the Company's ROE spill over and extension of the rate cap/CTC collection period should be granted.

G. Conclusion

In conclusion, for the reasons stated herein, a market-based valuation process should be used instead of a one-time administrative

determination of stranded generation plant-related costs. This market-based valuation could occur either through a panel of experts, subject to Commission review, or a generation plant auction. If a one-time administrative determination is required, then OTS proposes a $1,025.32 million valuation (NPV) of stranded generation plant ($686.54 nuclear and $338.78 fossil), in comparison to the Company's $1,541.68 million. See, Appendix, Table 1. The total OTS stranded cost allowance, including regulatory assets, is $1,378.68 million, in comparison to the Company's $1,898.96 million. OTS Ex. No. 4-SR, Sch. 1; Appendix, Table 1; Duquesne February 6 fax memo.

In OTS' view, Duquesne's proposed deferral of the final stranded generation plant-related cost determination until 2003 is not forbidden by the Competition Act, and is consistent with the statutory definition of stranded costs and principles of statutory construction.

OTS supports the Company's proposal to defer the final valuation with two modifications: (1) a possible extension of the CTC and rate cap period to prevent "rate shock" and (2) use of 10.50% for the ROE spill over proposal. These modifications are reasonable and should be adopted.

Duquesne's claim for stranded costs relating to the cold reserved units should be rejected. In addition, Duquesne's claim of $41.11 million for M & S and Fuel-Related Sunk Costs should be rejected. The resulting net book

value of stranded generating plant is $1,139.22 million ($764.14 million nuclear and $375.08 million fossil). Appendix, Tables 2, 3, 5 and 6.

The Company's delayed entry portfolio should be used to determine the market value of Duquesne's generation plants, if a one-time administrative evaluation as of January 1, 1999 is required. This portfolio provides for a plant margin between the low and high market value portfolios, which provides for a fair and balanced estimation of the market rate. This portfolio is premised on the assumption that new combined cycle capacity would become economic after 2006, and that assumption is reasonable and supported by the record. The result is an increase in market value of $73.9 million for nuclear and $57.7 million for fossil above the Company's levels. Appendix, Tables 2 and 3.

The Company's claim for PV of Costs Independent of Operation should not be allowed. Appendix, Tables 2 and 3.

For all the reasons stated herein, Duquesne's nuclear decommissioning stranded cost claim should be reduced by $53.9 million to disallow the contingency factors and to recognize that generation customers should also "pay for" decommissioning. The balance, after reflection of the decommissioning fund amount as of December 31, 1998, is $3.5 million to be collected from current ratepayers through the CTC. Appendix, Table 2. Similarly, Duquesne's fossil decommissioning stranded cost claim should also

be reduced by $24.9 million to disallow contingency factors and to recognize that generation customers should also "pay for" decommissioning. The balance is a stranded cost allowance of $41.6 million, to be recovered from current ratepayers through the CTC. Appendix, Table 3.

The Company's $3.92 million regulatory asset claim, net of taxes, for deferred caretaker costs relating to the cold reserved units, should be rejected. Appendix, Table 4. This claim is not recoverable under current regulatory practice and therefore is not recoverable as a regulatory asset stranded cost under the Competition Act.

Finally, for the reasons set forth herein, the OTS stranded cost recovery proposals with respect to the Company's ROE spill over and extension of the rate cap/CTC collection period should be granted.

V. THE COMPETITIVE TRANSITION CHARGE

A. Conceptual Disputes Regarding Calculation of CTC/CGC

1. Differences in Overall Approach (e.g., CTC or CGC as Residual; OCA Proposal)

This issue was not addressed by OTS.

2. Other Conceptual Disputes

(a) CGC Calculation; Annual Adjustments v. Fixed Schedule

This issue was not addressed by OTS.

(b) Determination of Class Responsibility for Stranded Costs

This issue was not addressed by OTS.

(c) Levelized CTC v. Other Methods

This issue was not addressed by OTS.

(d) Duquesne's Rate Redesign Proposal

This issue was not addressed by OTS.

(e) Other Conceptual Disputes

This issue was not addressed by OTS.

B. Other Disputes Regarding Specific Proposals

1. Duquesne

This issue was not addressed by OTS.

2. OCA

No OTS position.

3. DII

No OTS position.

4. Other Proposals

No OTS response.

C. Other Issues Addressed in PECO Order

No OTS response.

D. Conclusion

This subject area was not addressed by OTS herein.

VI. RATE OF RETURN/DISCOUNT RATE

A. Introduction

It is well established that a fair and reasonable overall rate of return is one which will allow a utility the opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period that the Company's rate will be in effect. It is the Company's burden, in this case, to prove that its recommended 11.65% return on common equity is required to cover capital costs and to assure confidence in the financial integrity of the utility so as to maintain credit and attract capital at reasonable rates. See Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944). OTS submits that the evidence submitted by Duquesne in support of its 11.65 recommended return on equity fails to meet this standard.

In the Bluefield water case, supra, the United States Supreme Court provided a criteria by which regulators are to be guided for purposes of determining a fair rate of return for a public utility. In this case the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on

> investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

See Blue Water Works & Improvement Co. v. Public Service Comm. of West Virginia, 262 U.S. 679, 692-93 (1923).

In Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) the Court focused particularly upon the equity return. The Court stated:

> . . . It is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends.
>
> . . . By that standard the return to the equity owner should be commensurate with risks on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and capital.

See Hope at 603.

The Pennsylvania Supreme Court has provided additional analysis to the Hope decision. In Pennsylvania Electric Co. v. Penna. Public Utility

Comm., 509 Pa. 324, 502 A.2d 130 (1985); appeal dismissed, 476 U.S. 1137, 106 S. Ct. 2239, 90 L.Ed.2d 687 (1986), the Pennsylvania Supreme Court stated:

> We do not believe, however, that the Hope decision stands for the proposition . . . that the end result of a ratemaking body's adjudication must be the setting of rates at a level that will, in any given case, guarantee the continued financial integrity of the utility concerned.
>
> Rather, the Hope decision requires only that the regulatory authority balance consumer and investor interests to determine "just and reasonable" rates.

The Penelec decision interprets Hope as requiring a balancing of consumer and investor interests to determine just and reasonable rates. OTS contends that the 11.65 return on equity proposed by Duquesne in the case at bar provides rates that would be far greater than the level needed to satisfy the standards set forth in Hope.

The determination of a fair rate of return requires an analysis of the proportion of each type of capital which has financed the rate base and an assignment of a cost rate to each. The cost rate of debt is fixed and can usually be computed accurately. The cost rate of common equity varies and is much more difficult to measure.

B. Duquesne's Position

Duquesne's witness, Dr. Jeffrey D. Makholm, concluded that the Company should be afforded an opportunity to earn an 11.65% return on common equity. This return recommendation is based upon Dr. Makholm's use of a discounted case flow (DCF) model analysis performed on a proxy group of U.S. Electric Utilities. See Duquesne Statement 2, pages 2-7. Although Company witness Makholm's recommended cost rate for common equity is 11.65%, the direct testimony of Duquesne witness D. J. Clayton states that 11.5% is the Company's claimed cost of common equity. According to Mr. Clayton, this 11.5% claim is conservative. See Duquesne Statement No. 2, page 47. Correspondingly, according to Mr. Clayton, the Company's after tax discount rate for use in computing present value of stranded costs is 7.83%. See Company's Filing, Volume IX, Item No. L-8, page 1 of 1.

C. OTS's Position

In ascertaining a fair and reasonable rate of return, OTS adopted the Company's test year capital structure which consists of 50.23% long-term debt, 9.69% preferred stock, and 40.08% common equity. Additionally, those cost rates accompanying long-term debt and preferred stock were also adopted. See Duquesne Filing, Volume VII, Items Nos. H-2 and H-7 and OTS Statement 1, p.26.

OTS's major source of contention with the Company's rate of return recommendation lies in the area of the cost of common equity. It is OTS's position that the cost of common equity should be no more than 10.5%. Correspondingly, OTS admits that, not only is the 11.65% recommended by Duquesne witness Makholm excessive but so is the 11.5% recommendation made by Duquesne witness Clayton.

In arriving at his 10.5% cost of common equity recommendation, OTS witness Jeschke did not utilize the barometer group of the U.S. Electric Utilities as did Dr. Makholm. Instead, witness Jeschke composed a barometer group of 13 electric companies from the eastern and central United States with risk factors similar to Duquesne and nuclear generating generally in excess of 30% since Duquesne's nuclear capacity is approximately 29%.

It should be mentioned that, in adopting Duquesne's capital structure, OTS witness Jeschke examined the historical common equity ratios for the electric barometer group. This analysis indicated that the Company's recommended 40.08% common equity ratio is lower than the average of the group. See OTS Exhibit 1, Schedule 3. Since common equity rates cost more than debt and preferred stock, the use of Duquesne's lower than average common equity ratio will result in lower than average overall cost of capital. Generally, a higher common equity ratio indicates lower financial risk.

Therefore, while Duquesne's capital structure is acceptable, a higher than average cost of equity is warranted. See OTS Statement No. 1, Page 11.

1. Cost Rate of Common Equity

To ascertain a fair and reasonable cost rate for common equity, comprehensive financial analysis is necessary. The determination of a cost rate for common equity requires the exercise of informed judgement based on financial data and investors expectations during various segments of the business cycle. It is necessary to consult the market place for insight into the cost rate for common equity since investors determine the price at which common equity capital will be provided. It is also necessary to review historic and current financial and economic data as well as prospective estimates of inflation rates, interest rates, and the state of the economy in general. Properly matching these costs indicators to the current expected phase of the business cycle will provide a reasonable, but not excessive, return on common equity. Thus, the Company will be able to compete for new capital in the market place with company's of comparable risk. See OTS Statement 1, page 12.

a. Discounted Cash Flow (DCF) Analysis

To determine a recommended cost of common equity, OTS witness Jeschke utilized the discounted cash flow method. This method has been consistently approved by the Commission to develop equity costs. To compute the various components of the DCF method, Mr. Jeschke replied upon

current, historic and forecasted market data for his electric barometer group. He also analyzed historical, current and prospective interest rates. Such an analysis is necessary to insure that one's recommended market determined cost of equity reflects changes in economic conditions.

The underlying principles of the DCF method recognizes that when investors buy stock they expect to receive a total return consisting not only of dividends, but also of capital appreciation. The cost rate yielded by the DCF technique for a public utility is the sum of the expected dividend yield on the stock during the coming year and the expected growth in dividends per share. The formula for the DCF method is:

$$k = D1/Po + Gn$$

where:

k = expected rate of return
D1 = indicated dividend payment expected during the course of the next year
Po = current stock price
Gn = dividend growth expected over the long-run period "n"

(i). Dividend Yield

In theory, the DCF advocates the use of the most current dividend yield. For purposes of ratemaking, a dividend yield that is representative of the prospective period for which new rates will be in effect must be determined. Ratemaking is a forward looking as well as a long run process. Therefore, an

analysis cannot be based solely upon short term spot market data. This is because investors are continually changing their opinion concerning the relative worth of debt and equity on a monthly, weekly, or in some cases, a daily basis, depending on changes in the economy or the financial position of the company. A spot rate of return which may seem appropriate for current ratemaking purposes may be too high or too low at a later point in time depending upon changing economic conditions in the market place.

Mr. Jeschke determined the dividend yield portion of the DCF formula by simply dividing an expected dividend by a representative stock price. To do this, Mr. Jeschke used the indicated expected dividend payment and representative stock price found in publications such as Standard and Poors Stock Guide and Barrons National Business and Financial Weekly. Specifically, in the present case, Mr. Jeschke utilized the current dividend yield presented in the September 1, 1997 Barrons National Business and Financial Weekly and a 52 week average dividend yield. See OTS Statement 1, page 14.

In the case at bar, Mr. Jeschke determined the dividend yield by giving weight to the 52 week average dividend yield, the current dividend yield and the medians. The dividend used to determine the dividend yields for each company is the current dividend reported in the September 1, 1997 Barrons National Business and Financial Weekly. The median 52 week and median

current dividend yield is 6.91 and 6.86%, respectively. See OTS Exhibit No. 1, Schedule 4, Column 2, lines 15 and 16. The average 52 week and average current dividend yield is 7.02 and 6.92%, respectively. See OTS Exhibit No. 1, Schedule 4, Column 7, lines 13 and 14. Mr. Jeschke utilized 7% as a presentative dividend yield in his DCF analysis. The 7% is the unadjusted dividend yield that was used to develop OTS's discounted cash flow method results. See OTS Exhibit 1, Schedule 7, OTS Statement No. 1, p. 26.

Mr. Jeschke also computed a yield adjustment by multiplying the 7% dividend yield by 1/2 of the next periods dividend growth rate. This adjustment was made because the dividend yield from the Barrons National Business and Financial Weekly may not reflect the annualized increases in quarterly dividends. Therefore, this adjustment reflects any annualized effect if increases in quarterly dividends occur. Mr. Jeschke has adjusted the dividend yield by 1/2 of the 2.5 - 3.5% dividend growth rate recommendation to produce an adjusted dividend yield. This adjustment causes the yield to increase by 9 - 12 basis points to a range of 7.09 - 7.12%. See OTS Exhibit 1, Schedule 1; OTS Exhibit 1, Schedule 7, Note 1 at line 6; OTS Statement No. 1, pages 26 - 27.

(ii). Growth Rate

The growth rate component of a DCF methodology is more subjective and somewhat more difficult to determine than the dividend yield.

The growth rate is used to estimate perpetual capital appreciation. One way to derive a dividend growth rate is to use historical data. However, it is important not to solely rely on historical information since utilities can increase dividend payments as earnings per share rise and, since earnings per share drive dividends per share, dividends per share will tend to rise in the future reflecting increased earnings per share forecasts. Thus, when reputable analysts forecasts are available such as those found in the Value Line Investment Survey or Standard and Poors Earnings Guide, historical information should not be the sole source driving ones growth rate calculation. The DCF analysis which is developed by utilizing analysts forecasted growth rates is indicative of estimated future economic conditions and specific company and industry risk factors. See OTS Statement 1, p. 27.

To calculate his DCF growth rate, OTS witness Jeschke analyzed historical growth and dividends per share (DPS) and earnings per share (EPS) for the electric barometer group. Mr. Jeschke also reviewed the forecasted earnings and growth rates as shown by Value Line and Standards and Poors. See OTS Exhibit No. 1, Schedule 8.

In his testimony and exhibits, Mr. Jeschke shows the results of the historical compound dividend (normalized five year) and historical log-linear dividend (5 years). The time covered in this analysis is a five year historical and a five year forecast. The historical compound dividend and log-linear

dividend is 1.64% and 1.77% while the medians are 2.21% and 1.45%. On the other hand, the average historical compound earnings and log-linear earnings growth rate is 2.73% and 2.92% while the medians are 3.09% and 4.09%. See OTS Exhibit No. 1, Schedule 8 and OTS Statement 1, page 28.

Forecasted dividends from the Value Line Investment Survey for the electric barometer group reflect an average of 0.38% and a median of .50%. Correspondingly, forecasted earnings from the Value Line Investment Survey for the electric barometer group reflect an average of 3.58% and a median of 3.50% while forecasted earnings from the Standard and Poors Earnings Guide for the electric barometer group reflect an average of 2.92% and a median of 3.0%. See OTS Exhibit No. 1, Schedule 8, Columns 7 and 8.

In his testimony Mr. Jeschke stated that in determining the growth rate for use in his DCF model he gave primary weight to expected earnings growth rates. This is because earnings for utilities can be volatile and growth rates computed from those earnings may not be indicative of long term growth potential. Yearly fluctuations in earnings can result in distorted growth rates. On the other hand, dividend growth rates are less volatile and more indicative of management's long term earnings expectations. One finds more information is implicitedly contained in expected earnings growth rates. The historical data, on the other hand, is accounted for both in the forecasted growth as well as in the expectation of the wide array of economic variables. Thus to give

significant rate to historical growth information would have the effect of considering this information twice in a single calculation. See OTS Statement 1, page 29.

Mr. Jeschke determined that a 2.5% - 3.5% growth rate is appropriate in this case. See OTS Exhibit No. 1, Schedule 8. Mr. Jeschke's opinion is based upon the fact that the average historical earnings and dividend growth rates are in the 1.64 - 2.92% range. The average forecasted earnings growth rates are 2.92 and 3.58% and the average forecasted dividend growth rate is 0.38%. The median forecasted growth rates are 3.0 and 3.5% with a forecasted dividend growth rate of .50. The median historical earnings and dividends growth rates range from 1.45 to 4.09%. However, the historical earnings growth rate of 4.09% is unlikely to be sustainable for the electric barometer group. Therefore, the forecasted earnings growth rate of 3.0 and 3.5% reflect sustainable growth which Mr. Jeschke utilized in his DCF analysis.

(iii). DCF Results

In OTS Exhibit No. 1, Schedule 7, Mr. Jeschke sets forth the results of his DCF analysis. First, Mr. Jeschke adjusted the 7% recommended dividend yield by 1/2 of the 2.5% low end of his growth rate range. The adjusted dividend yield is 7.90%. The 9.95% low end of Mr. Jeschke's DCF

range is the sum of the adjusted dividend yield (7.9%) and the 2.5% growth rate. See OTS Exhibit No. 1, Schedule 7, Column 2.

Additionally, Mr. Jeschke adjusted the 7% recommended dividend yield by 1/2 of 3.5% high end of his growth range. The adjusted dividend yield is 7.12%. The 10.62% high end of OTS's DCF range is the sum of 7.12% adjusted dividend yield in the 3.50% growth rate.

Based on this analysis, it is OTS's position that 9.50% - 10.50% represents a reasonable cost range of common equity for a publically traded electric company. See OTS Statement 1, pages 31-32.

OTS did not apply the DCF analysis for DQE. This is because, in comparison to Mr. Jeschke's 7% recommended dividend yield for the electric barometer group, DQE's current yield is unusually low. OTS contends that this is probably due to investors' expectation of a 20% increase in the dividends that would result from DQE's merger of Allegheny Power System. It is clear that DQE's current dividend yield is not reflective of the company's long term earnings potential. Therefore, OTS submits that it is inappropriate to use DQE's current dividend yield in a current DCF analysis to determine Duquesne Light Company's cost rate of common equity.

(b). Barometer Group Selection

As stated previously, in order to determine a market based cost of common equity, OTS witness Jeschke utilized a 13 company barometer group

of publicly traded electric companies. This is because Duquesne is a wholly owned subsidiary of DQE. Consequently, it is necessary to use a suitable proxy or barometer group of publically traded electric companies that provide services similar to those provided by Duquesne, to determine the rate of return on common equity for Duquesne. Though the companies will certainly differ in some aspects, if one focuses on similarities of companies one can determine which companies will compose a barometer group. This can be accomplished by analyzing some of the key market information and risk indicators. Mr. Jeschke's barometer group in this case included the following companies:

1. Atlantic Energy, Inc.
2. Baltimore Gas and Electric Company
3. Boston Edison Company
4. Carolina Power and Light Company
5. Dominion Resources, Inc.
6. Duke Power Company
7. GPU, Inc.
8. IEF Industries
9. PECO Energy Company
10. PP&L Resources, Inc.
11. Public Services Enterprises Group, Inc.
12. Rochester Gas and Electric Corporation
13. Unicom Corporation

See OTS Statement 1, page 16.

OTS contends that this group of 13 electric companies satisfies certain criteria that are important to fairly determine Duquesne's rate of return on common equity. This criteria include their location, financial risk, and nuclear generating capacity.

(c). Risk Comparison

Since Duquesne does not have market data available which can be utilized in a risk analysis, OTS witness Jeschke employed DQE's market data sent as a proxy for Duquesne. This is particularly appropriate since 92.5% of DQE's operating revenues are derived from Duquesne's sale of electricty. Additionally, the percentage of electric operating revenues to total revenues in Mr. Jeschke's 13 company electric barometer group is 91.46% of total revenues. See OTS Exhibit No. 1, Schedule 3.

In analyzing risk indicators, Mr. Jeschke considered nuclear generation percentage, total capacity, equity ratio, beta safety rank and financial strength. When these indicators are carefully scrutinized, it is clear that the barometer group is a very close representation of an electric utility with DQE's characteristics.

For example with regard to nuclear generation, the average percentage of nuclear generation for the barometer group is 35.85% and the median is 32% with the range from 15% - 67%. Correspondingly, DQE's data reflects nuclear generation of 29%. The significance of this factor is that the barometer group of the electric companies is largely exposes to risks associated with nuclear generation. Since DQE's percentage of nuclear generation is slightly lower than the median of the range, this indicates a lower risk associated with nuclear generation on the part of DQE, than the average.

In relation to financial risk, DQE's common equity ratio of 45.15% and Duquesne's common equity ratio of 40.08% is lower than the barometer group's average of 47.58% and median of 47.01%. The range of common equity ratios for the electric barometer group is 43.74% - 53.66%.

When one takes investment risk into consideration, DQE's beta of .75 compares favorably to the electric barometer group's of 0.78 and median of 0.70. DQE's safety rank of 2 is higher than the electric barometer group's average of 2.4 and median of 3.0. Additionally, DQE's financial strength with a rating of "A" is higher than the electric barometer groups rating of "B++" and median of "B++". This clearly indicates that DQE is somewhat financially stronger than the electric barometer group. See OTS Exhibit No. 1, Schedule 3. When all these factors are taken into consideration, it is apparent that the electric barometer group is a very close representation of an electric utility with DQE's characteristics. See OTS Statement 1, pages 18 - 20.

(d). Alternative Investments

OTS's analysis incorporates the effect of changing business and economic conditions by utilizing market based data. This is because financial markets take all factors into account when accessing investments. OTS witness Jeschke compared the electric barometer group's common stock dividend yields to yields on Moody's A-Rated Public Utility Bonds, long term government

bonds, intermediate term government bonds and short term government issues for the period 1981 - 1996. See OTS Exhibit 1, Schedule 5.

This analysis indicates that the 12 month average for 1996 for the electric barometer group's common stock yield dividends and yields on utility bond and government securities are at relatively low levels in terms of yields experienced since 1981. Mr. Jeschke's analysis clearly shows that the electric barometer group's dividend yields and long term bond yields are near the low end of the 1981 - 1995 range. It also indicates that shorter term government securities tend to become more volatile than long term bonds and utility stock yields. See OTS Statement 1, pages 22-23.

The significance of this analysis is to demonstrate that the electric company dividend yields reflect changes in yields on alternative income paying investments such as bonds. Since the dividend yield composes the greatest portion of the expected total return for electric utilities, it is only logical that assumptions made about the level and trend of dividend yields and yields on alternative investments generally hold true for the total expected return on common equity.

OTS witness Jeschke also summarized bond yield forecasts as presented by the Blue Chip Financial Forecast. These Forecasts are published monthly. Mr. Jeschke analyzed the short term forecasts and the long term estimates concensus published in October 1997 and June 1997 respectively.

The purpose of reviewing the October, 1997 forecast was to note the direction yields are expected to take over the short run (fourth quarter of 1997 through the first quarter of 1999). The long range concensus demonstrates the continuity of the forecast.

A review of the results of the October, 1997 forecasts show a expected decrease in "A" rated utility bonds of 20 basis points from the fourth quarter of 1997 through the first quarter of 1999 (7.60 - 7.40%). See OTS Exhibit No. 1, Schedule 6. The same holds true for the long term treasury bond yield. In fact, between the fourth quarter of 1997 through the first quarter of 1999, the long term treasury bond yield is expected to decline by 10 basis points from 6.5% - 6.4%. See OTS Statement 1, page 24.

OTS witness Jeschke also analyzed the long range concensus forecasts. These forecasts relate to bond yields and the prime rate is presented on OTS Exhibit No. 1, Schedule 6. The long range estimates are provided both separately for the years 1998 through 2002 and collectively as one forecast for the years 2003 - 2007. This concensus clearly indicates that "A" rated utility bonds are expected to decline from 7.7% in 1998 to 7.2% in 2002, and to 7.0% from 2003 to 2007. The long term treasury bond yields reflects a similar decline. See OTS Exhibit No. 1, Schedule 6 and OTS Statement 1, pages 24 - 25.

2. Additional Analysis

OTS witness Jeschke an additional analysis to determine the expected return on common equity for the next three to five years for the electric company barometer group. He calculated the expected total of DCF method return for Value Line Electric Utilities using forecasted information found in the Value Line Investment Survey. See OTS Exhibit No. 1, Schedule 9.

The reason that this additional analysis was performed is because Value Line provides forecasted growth rates for both earnings and dividends and dividend yields for the coming year. In his analysis Mr. Jeschke used the forecasted dividend yield and growth rates provided to investors by the Value Line Investment Survey. The growth rate is forecasted three to five years into the future. Thus, the results of the analysis reflect current and forecasted data. See OTS Statement 1, page 33.

Mr. Jeschke found that the mean total expected common equity for the electric company barometer groups utilizing Value Line's forecasted dividend growth rate is 7.17%. The median of the total common equity return using dividend growth is 7.5% while the range of total equity returns using dividend growth is 3.10-9.10%. Mr. Jeschke also calculated the mean total expected common equity return of the electric barometer group utilizing Value Lines earnings growth rate of being 10.37% and the median of the total

expected equity return using earnings growth rates as 10%. Thus the total expected equity returns using earnings growth rate 8.50 - 13.10%.

At first blush, it becomes apparent that there are significant differences between the forecasted total equity return using dividend growth and the forecasted total equity return using earnings growth. According to Mr. Jeschke, this difference is due to the fact that earnings growth rates are expected to continue to increase during the forecasted periods while dividend growth rates are not expected to increase during that period at the same pace.

Mr. Jeschke states that, in the electric utility markets, investors should not look for significant increases in dividends during the next three to five years. He opines that, in response to a perceived increase in business risk resulting from the transition to a competitive environment, dividend growth is being restrained in order to strengthen equity ratios. It is apparent that the electric environment is changing and those electric utilities that will fair best are those with low rates relative to their competitors and those that are financially strong. However, low rates will slow earnings growth and, consequently, dividend increases. It is readily apparent that the results in the Value Line Analysis support the reasonableness of OTS's recommended 9.50% to 10.5% recommendation of a fair and reasonable return on common equity. See OTS Statement 1, pages 34 and 35.

It is OTS's position that, based on the 9.50% to 10.50% recommended cost rate for common equity for the electric barometer group, or 10.50% return on common equity is appropriate in this case for Duquesne. The reason for this recommendation is because Duquesne's test year capital structure represents a below average business position and a current BBB+ senior debt rating. Duquesne has a lower common equity ratio which suggests higher financial risks. Because of this slightly higher financial risk, OTS recommends that the return on common equity for Duquesne should be at the upper end of OTS's calculated range. See OTS Statement 1, page 36.

D. Overall Weighted Cost of Capital

OTS submits that a 10.5% cost rate for common equity combined with the Company's historic test year's December 31, 1996, capital structure and the embedded cost of 8.51% for long term debt and a 7.45% cost rate for preferred stock results in an overall rated cost of capital 9.20%. See OTS Exhibit No. 1, Schedule 1, Column 4.

E. Pre-Tax Interest Coverage

OTS witness Jeschke also performed an interest coverage analysis to check the reasonableness of his 9.20% overall rate of return recommendation. This analysis clearly indicated that OTS's recommendation was fair and reasonable. As can be seen in OTS Exhibit No. 1, Schedule 9,

OTS's recommended 9.20% overall rate of return provides that pre-tax interest coverage of 2.97 times.

Mr. Jeschke utilized the Standard and Poors utility financial benchmark ratios for electric utilities. This study is found in the Standard and Poors Global Sector Review of July 1994. According to this publication, the current data for the Duquesne Light Company is a investment grade of BBB+. The pre-tax coverage benchmark for an "A" rating ranges between 2.75 - 4.50 times and for a BBB rating in the range of 1.75 - 3.50 times. Therefore, the pre-tax coverage of 2.97 times which OTS derives from its overall rate of return recommendation is clearly within the range of coverage of the electric barometer group. See OTS Statement 1, pages 39 and 40.

F. Discount Rate

OTS witness Jeschke calculated the after tax weighted cost of capital for the company to utilize in its present value calculation related to the determination of the company's stranded costs. OTS contends that Mr. Jeschke's recommended 10.50% cost rate for common equity, combined with the Company's historic test year, December 31, 1996, capital structure and the embedded cost rates for long term debt and preferred stock results in an overall weighted discount cost of capital of 7.43%. This is 40 basis points lower than the Company's recommendation of 7.83%. See OTS Exhibit No. 1, Schedule 1, Column 6; OTS Statement 1, p.40.

G. Duquesne's Cost of Capital Position

OTS contends that Duquesne's witness Makholm's cost of capital testimony is flawed for a number of reasons. These flaws have caused Dr. Makholm to over estimate the Company's cost of equity requirement.

One area in which OTS disagrees with Duquesne witness Makholm is his barometer group selection. OTS contends that Dr. Makholm's selection of his barometer group is inappropriate. This contention is based upon the fact that Dr. Makholm's barometer group lacks substantial similarity to Duquesne because of the 17 company barometer group which he choose, eight of these companies do not have nuclear power generation. Additionally, 13 of his 17 companies have purchased power of a large portion of their generation. Though Dr. Makholm admits these flaws, he states that these are not important factors in this case. See Duquesne Statement No. 12, page 20. OTS disagrees. This office submits that the barometer is not a representation of an electric utility with DQE's characteristics and, therefore, is not a fair and reasonable proxy to determine a market based expected cost for common equity for Duquesne.

Specifically, for Duquesne witness Makholm to include a large number of companies which do not have nuclear power brings his proposed barometer group under severe scrutiny. Nuclear power plants will impact revenues in the future because of the high expense of recovery. The percentage

of nuclear generating is a variable where an expected large stranded cost associated with nuclear plant is found.

Another problem with Duquesne witness Makholm's analysis is that he performed an ex-dividend cost date adjustment on all stock prices. This, he claims, is to remove the known effect that the next quarterly dividend will have on the stock price. This adjustment is made by removing from the stock price the portion of the dividend which is already accrued. See Duquesne Statement No. 12, pages 21- 23.

It is OTS's contention that such an adjustment for an ex-dividend is not appropriate for use in the DCF analysis. First, Dr. Makholm used a 52 week closing price average for the stock price. This negates any use of an adjustment to the stock price and any change in stock price for seasonal or quarterly events would average out.

Secondly, the stock price change cannot, in any way, be attributed to one factor such as a dividend accumulation of payment. The market price a stock moves up or down due to many factors and events and cannot be attributed to any single factor. See OTS Statement 1, p.43.

OTS contends that a third factor that causes Dr. Makholm's analysis to be flawed is that he utilized an inappropriate growth rate. The results Dr. Makholm's individual growth rate analysis produced a 3.47 and 4.31 rate an average of 3.89%. According to the Company's Exhibit JDM-7,

10 of the 17 companies in Dr. Makholm's barometer group have an average growth rate below 3.50%. Therefore, a growth rate above 3.50% is clearly not sustainable and such a growth rate should not have been utilized by the Company in its DCF calculations.

It is OTS's position that a fourth problem with Dr. Makholm's analysis is that he utilizes 5% for selling and issuance costs in his DCF model calculation. See Duquesne Statement No. 12, page 28. OTS contends that this is clearly inappropriate. The selling of issuance cost are an additional cost of capital that incurred at the time of issuance. The current market price of common stock already reflects these items as investors have already capitalized the expenses in determining the market price at the time of purchase. See OTS Statement 1, p.45.

It must be remembered that Duquesne's last offering was September of 1981. See Duquesne Statement No. 12, Exhibit JDM-11. Thus, any analysis would have already taken these items into consideration. And, therefore, there is no reason to make additional adjustments to account for selling and issuance costs. In fact, it seems that the only purpose that this adjustment serves is to overstate Duquesne's cost rate of common equity. There is absolutely no evidence that Duquesne is issuing any new common stock at the present time. See OTS Statement 1, pages 45 - 46.

H. Conclusion

Because of the foregoing, OTS submits that Dr. Makholm's 11.65% recommendation is overstated by at least 115 basis points. OTS recommends that the ALJ and the Commission should give weight only to the DCF method to determine the cost rate of common equity. This means that only reasonable and supportable growth rates and the proper dividend rate such as OTS witness Jeschke's 7% on DCF based cost of common equity. Thus, the Commission should permit a rate of return on common equity of no more than 10.50%. Additionally, the Commission should allow a discounted cost of capital of no more than 7.43% for Duquesne's stranded costs. See OTS Statement 1, page 47.

VII. SPECIAL CUSTOMER CLASSES

A. Rule 4 Contracts

Not addressed by OTS.

B. Riders 8 and 20

Not addressed by OTS.

C. Self-Generation

Not addressed by OTS.

D. Other Tariff-Related Issues

Not addressed by OTS.

VIII. COMPETITIVE SAFEGUARDS

A. Code of Conduct

Not addressed by OTS.

B. Pro Forma Tariffs

Not addressed by OTS.

IX. DUTY TO SERVE

A. Service to Returning Customers

Not addressed by OTS.

B. Provider of Last Resort

Not addressed by OTS.

C. Electric Transmission and Distribution Service

1. Unbundling of the Customer Services

a. Introduction

Rate unbundling is the breaking down of a total rate into its costs components. Specifically, a distribution rate will have costs components consisting of metering, billing, universal service and service drop lines. According to 66 Pa. C.S. §2806(e) electric distribution utilities are required to unbundle its distribution rate. Thus the law requires Duquesne in this case, to submit unbundled prices for generation, jurisdictional transmission, distribution and other services. See OTS Statement 3, p.10.

b. Resolution in Generic Proceedings v. Resolution in this Case

Not addressed.

c. Interim rules applicable to Duquesne

Not addressed.

d. Specific Services

(i). Customer Billing

It is OTS's position that the universal service charge should appear on the customer bills as a separate line item. OTS's position is based upon the fact that, as a separate line item, this charge and its resultant and costs will be easier to track. It will also hold Duquesne more accountable for these costs and inform the customers of these costs.

OTS submits that whenever specific charge is being billed to customers, the customers should have such a charge as a specific line item on their bill so that they are aware of how the money they are paying to the utility is being utilized.

Although there are some costs that are difficult to ascertain and delineate, this universal service charge is, clearly, not difficult to calculate. The cost per customer is readily obtainable and the customers should have the ability to see this charge on their bills to make them aware that this specific charge is being paid by them. Additionally, it will allow the customers to be

educated as to exactly how much they are individually, responsible to pay for this service charge. OTS contends, that unless the Company is trying to avoid the scrutiny of their customers, or is not willing to advise the customers of how the revenues from those customers are being used, there is absolutely no reason for the universal service charge not to appear as a separate line item on Duquesne's customers' bills. See OTS Statement 3, p.10.

(ii). Metering

It is OTS's position that billing and metering costs should also be specifically delineated on the customers bills. These costs are borne by the ratepayers. OTS submits that the generation supplier can offer billing and metering at a lower cost than the distribution company, the ratepayer should have the option to choose the least expensive alternative. This can only be known and measured by the ratepayer if these costs are unbundled. Once again, unless the Company is concerned that it will loose its customers because the customers will choose a more advantageous billing and metering system, the Company should be willing to unbundle these services.

It must be remembered that, if one is committed to competition, the only way that competition becomes effective is if the customers for whom the electric distribution companies compete are fully and clearly advised as to what their alternatives are. This can only be accomplished if the customers know how much each service costs them when provided by the electric

distribution company so they can make an intelligent choice as to whether or not they wish their services continue to be provided by that company or by an alternative source. See OTS Statement 3, p.10.

e. Conclusion

It is OTS's position that a bundled distribution charge may confuse the ratepayer whenever a component of the distribution charge increases. An unbundled distribution charge will allow the customer to know the reason for the increase. This is extremely important when customer knowledge and education is considered. It is also important when considering customer satisfaction in dealing with the company. Imagine a customer's confusion when that customer sees a higher bill because of the distribution charge component that is not specified on the bill. The customer will know that the Company has not been in for any type of rate increase but, nonetheless, it will appear as though the Company has received such a rate increase.

An unbundled distribution charge would serve to avoid confusion. A customer could easily ascertain from the bill that a certain component of the distribution charge has increased. The customer will know which portion of the bill that has been affected and confusion will be avoided.

Additionally, such things as Demand Side Management and social costs are not only related to distribution service and should be separately stated on the bill. Once again this allows the customers to be advised of what they

are paying for when they pay their electric bills. Perhaps, if customers see what they are paying for through their bills, they may disagree with how their money is being spent. But, at the very least, they will be advised and informed as to how the money which they pay for electric service is being used by the Company. An informed public can only be advantageous.

In summary, it is OTS's position that the universal service charge portion of a customers' bills should be a separate line in the distribution portion of the customers' bills. This will fairly inform the customers of the services for which they are paying.

Billing and metering costs should also be specified on the customers' bills so that they can make informed decisions as to their choices for the provision of these services. If a less expensive supplier can provide those services at a lower cost, the customer should have the right to know this and act accordingly.

2. Agency

Not addressed by OTS.

3. Other Issues (e.g., CARS system)

Not addressed by OTS

D. Consumer Protection and Service Issues

1. Termination

Not addressed by OTS.

2. Switching Fees

Not addressed by OTS.

E. Partial Payments

Not addressed by OTS.

X. UNIVERSAL SERVICE AND ENERGY CONSERVATION

A. Introduction

The universal service fund charge is a fee that is designed to recover the costs of providing universal service and energy conservation for low income customers. Pursuant to the Electric Generation Customer Choice and Competition Act (66 Pa. C.S. §2801-2812), universal service and conservation is defined as:

> "... policies, protection, and services that help low income customer to maintain electric service. The term includes customer assistance programs,

termination of service protection and policies and services that help low income customers to reduce or manage energy consumption in a cost effective manner, such as the Low Income Usage Reduction Program, application of renewable resources and customer education".

See 66 Pa. C.S. §2803

According to Section 2804(8) and (9) of the Act, the cost of universal service is to be funded in each electric distribution territory by a non-bypassable, competitively neutral cost recovery mechanism that fully recovers the costs of universal service and energy conservation services. How such a cost recovery mechanism is to be designed is at the discretion of the Commission. See OTS Statement 3, p.7.

Currently, Duquesne's 1996 actual universal service and conservation fund expenses are approximately $12,275,000. These expenses are being recovered through existing rates. Those programs included in these expenses are the customer assistance program, smart comfort, customer assistance and referral evaluation service (CARES), hardship fund, gatekeeper, low income home energy assistance program (LIHEAP), write-offs and waivers.

B. Overall Funding and Rate Issues

1. Eligibility and Funding Levels

No addressed.

2. Cost Allocation and Rate Design

The Company proposes to establish the Universal Service charge on a per kwh basis for each rate class under its current tariff. The Company calculated the charge per kwh for each rate class based upon the allocation of distribution costs assigned to each rate class. See Duquesne Statement 14R, Exhibit JPF1. In its original filing, the Company approximated the funding for the Universal Service and Energy Conservation funding to be $12,183,000, but in the rebuttal testimony it is shown to be approximately $12,275,000. The Company also proposes to include the universal service charge within the distribution charge. See Duquesne Statement No. 14-R, pg.24, Exhibit JPF-1, p.6 The OTS disagrees with the Company's proposed application of the Universal Service charge and its presentation on customers' bills.

In his testimony, OTS witness Yarolin addressed the Company's universal service charge in the restructured environment. It is OTS's position that this charge should be on a customer basis rather than on a per kilowatt basis.

OTS's position is based upon the rationale that by applying a universal service charge based upon kilowatt usage, and applying the charge to all rate classes, high volume users would bear an excessive burden which would be discriminatory. On the other hand, by applying this none bypassable

universal service charge on a customer basis, there would be greater equity in sharing the cost for these social programs. See OTS Statement 3, page 6.

This recommendation goes along with OTS's second recommendation that all customer should bear the cost of maintaining the universal service and conservation fund. Though certain classes of customers may allege that its class is not responsible for Duquesne's poor customers, OTS submits that this rationale is unfair and short sighted.

OTS contends that if society benefits directly or indirectly from a sound universal service and energy conservation program, it is appropriate for all customer classes to share in the funding of these programs. Additionally, Section 2804 of the Electric Generation Customer Choice and Competition Act specifically requires the establishment of a none bypassable universal service charge. This certainly suggests that all customers, regardless of customer class, must contribute to the fund.

OTS views this issue as one of fairness. The poor are a social problem and if responsibility for helping the poor pay their electric bills is thrust upon Duquesne's customers, then the responsibility should be shared by all of Duquesne's customers. Those residential customers who pay their bills on time are no more responsible for Duquesne's low income customers than are Duquesne's commercial and industrial customers. This burden should be shared evenly.

If the universal service charge is applied to all customers, the monthly service charge per customer would be approximately $1.85 per month. This charge is determined by the dividing the 1996 universal expense of $12,275,000 by the average number of customers (579,740). This results in a figure of $1.76 per customer. When the Pennsylvania Gross Receipts Tax factor is applied, this produces a $1.85 per month universal service charge. See OTS Statement 3, page 8.

Finally, it is OTS's position that the universal service charge should appear as a line item on the customers' bills. The primary reason for this recommendation is that if this charge appears as a line item it make customers more informed of the composition of their bill. This will allow customers to understand where their monthly electric bill payments are being spent. Another reason to have the universal service charge appear as a separate line item is that it aides in tracking accountability of the universal conservation fund. It could be that when customers know what composes their cost of electric, they can make more informed choices about their choice of suppliers.

C. Specific Programs

1. CAP Program

Not addressed by OTS.

2. LIRUP

Not addressed by OTS.

3. Renewables

Not addressed by OTS.

D. Energy Conservation

In regard to energy conservation, OTS has addressed this issue previously in its Brief at X.B.2.

XI. CUSTOMER EDUCATION

A. Scope of Customer Education

1. State-Wide v. Company Specific

This topic was not addressed by OTS.

2. Role of EDC

This topic was not addressed by OTS.

B. Implementation Issues

This topic was not addressed by OTS.

C. Funding Levels and Recovery

This topic was not addressed by OTS.

XII. MISCELLANEOUS ISSUES

No OTS miscellaneous issues.

XIII. CONCLUSION

For all the reasons stated herein, OTS respectfully requests that its positions as set forth in the Conclusion Sections of Parts IV., VI, and IX. and X. of this Main Brief, and as set forth in the attached Appendix Tables, be adopted in this proceeding.

Respectfully submitted,

Kandace F. Melillo

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Wayne T. Scott
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APPENDIX

Duquesne Light Company

Summary of
Stranded Cost

(Net of Taxes)

($millions)

	Company Claim	Reference	Adjustments	Reference	Adjusted Amount	Reference
Nuclear	$ 934.40	Table 2	$ 247.86	Table 2	$ 686.54	Table 2
Fossil	$ 607.28	Table 3	$ 268.50	Table 3	$ 338.78	Table 3
Regulatory Assets	$ 357.28	Table 4	$ 3.92	Table 4	$ 353.36	Table 4
Total Net Present Value (NPV) in 1999 $	$ 1,898.96	Fax Memo Feb 6,98	$ 520.28		$ 1,378.68	OTS Ex. 4SR Fax Memo Feb 6,98
PUC Jurisdictional Percent	100%					

Table 1

Duquesne Light Company

Stranded Cost
Calculation - Nuclear
($millions)

	Company Claim	Reference	Adjustments	Reference	Adjusted Amount	Reference
a.Net Book Value	$ 788.59	See Table 5	$ 24.45		$ 764.14	See Table 5
b.(Market Value)	$ (7.20)	DJC-20,p2	$ (73.90)	DJC-20,pg34 OTS Stmt 4SR	$ (81.10)	
c.PV of Nuclear Decommissioning	$ 57.40	DJC-20,p2	$ 53.90	OTS Stmt 2	$ 3.50	
d.PV of Costs Independent of Operation	$ 95.61	DJC-20,p1 Fax Memo Feb 6,98	$ 95.61	OTS Ex. 4SR Fax Memo Feb 6,98	$ -	
e. Net Present Value (NPV) in 1999 $ (a+b+c+d)	$ 934.40		$ 247.86		$ 686.54	
Discount Rate	7.50%		0.00%		7.50%	
PUC Jurisdictional Percent	100%					

Table 2

Duquense Light Company

Stranded Cost
Calculation - Fossil
(Net of Taxes)
($millions)

	Company Claim	Reference	Adjustments	Reference	Adjusted Amount	Reference
a.Net Book Value	$ 448.36	See Table 6	$ 73.28		$ 375.08	See Table 6
b.(Market Value)	$ (20.20)	DJC-20,p2	$ (57.70)	DJC-20,pg34 OTS Stmt 4SR	$ (77.90)	
c.PV of Fossil Decommissioning	$ 66.50	DJC-20,p2	$ 24.90	OTS Stmt 2	$ 41.60	
d.PV of Costs Independent of Operation	$ 112.62	DJC-20,p1 Fax Memo	$ 112.62	OTS Ex. 4SR Fax Memo	$ -	
e. **Net Present Value (NPV) in 1999 $ (a+b+c+d)**	$ 607.28	Feb 6,98	$ 268.50	Feb 6,98	$ 338.78	
Discount Rate	7.83%		0.40%		7.43%	
PUC Jurisdictional Percent	100%					

STRANDED COST
CALCULATION - REGULATORY ASSETS
Net of Taxes
($Millions)

	** Company Claim	Adjustments		Adjusted Amount
a. Reg Tax Rec (SFAS 109)	$ 179.00	$ -		$ 179.00
b. Post-2005 Unamortized Debt Cost	19.04			$ 19.04
c. Pre-2006 Unamortized Debt Cost	9.80			$ 9.80
d. Deferred Rate Sync. Costs	23.50			$ 23.50
e. Deferred Employee Costs	13.83			$ 13.83
f. Deferred Nuclear Maintenance	1.90			$ 1.90
g. DOE Decommissioning	3.25			$ 3.25
h. Deferred Coal Costs	13.50			$ 13.50
i. Deferred Caretaker Costs	3.92	3.92	*	-
j. BV2 Training Costs	1.58			1.58
k. Low Level Radioactive Waste	2.27			2.27
l. Coal Cost Equalization	0.12			0.12
m. Pre-Accrue Nuclear Outages	10.29			10.29
n. SFAS 106 Deferral	1.92			1.92
o. Deferred Fuel Costs	6.73			6.73
p. Other	0.53			0.53
q. BV2 Sale/Leaseback Premium	55.13			55.13
r. Gain on Sale/Leaseback Tax Effect	0.17			0.17
s. Deferred Rate Sync. Costs (Tax)	0.21			0.21
t. Beaver Valley 2 Tax Effect	-			-
u. SFAS 109 Plant	-			-
v. Other Transition Costs	10.59			10.59
Net Present Value in 1999 $	$ 357.28	$ 3.92		$ 353.36
PUC Jurisdictional Percent	99.9%	99.9%		99.9%
Deferred Taxes on Regulatory Assets	$ (105.52)	-		$ (105.52)

* Duquesne Statement No. 4, page 14, The Direct Testimony of Morgan K. O'Brien.
* OTS Statement No. 4, page 20, The Direct Testimony of Paul J. Metro.
** Duquesne Fax Memo dated February 6, 1998.

Duquesne Light Company

Stranded Cost
Calculation - Nuclear
(Net of Taxes)
($millions)

	Company Claim	Reference	Adjustments	Reference	Adjusted Amount	Reference
a. Book Value of Generation Plant	$ 763.62	DJC-3,p24	0		$ 763.62	
b. (Deferred Taxes)	$ (239.89)	DJC-3,p24			$ (239.89)	
c. Working Capital	$ -	DJC-10			$ -	
c1. (ITC)	$ (46.78)	DJC-3,p25			$ (46.78)	
d. M&S and Fuel Related Sunk Costs	$ 33.40	DJC-13	$ 33.40	OTS Ex. 4SR	$ -	
e. PV of BV2 Lease Expense	$ 278.24	DJC-20,p1	$ 8.95	OTS Ex. 4SR	287.19	
f. Net Book Value (a+b+c+d e)	$ 788.59				$ 764.14	
g. (Market Value)	$ (7.20)	DJC-20,p2	$ (73.90)	DJC-20,pg34 OTS Stmt 4SR	$ (81.10)	
h. PV of Nuclear Decommissioning	$ 57.40	DJC-20,p2	$ 53.90	OTS Stmt 2	$ 3.50	
i. PV of Costs Independent of Operation	$ 95.61	DJC-20,p1 Fax Memo Feb 6,98	$ 95.61	OTS Ex. 4SR	$ -	
j. Net Present Value (NPV) in 1999 $ (e+f+g+h)	$ 934.40		$ 247.86		$ 686.54	
Discount Rate	7.50%	Duq. St.2,p35	0.00%		7.50%	
PUC Jurisdictional Percent	100%					

Table 5

Duquesne Light Company

Stranded Cost
Calculation - Fossil
(Net of Taxes)
($millions)

	Company Claim	Reference	Adjustments	Reference	Adjusted Amount	Reference
a.Book Value of Generation Plant	$ 606.91	DJC-3,p24	$ 65.58	DJC-3,p38&39 OTS Stmt 4SR	$ 541.33	
b.(Deferred Taxes)	$ (148.62)	DJC-3,p24			$ (148.62)	
c.Working Capital	$ -	DJC-10			$ -	
c1.(ITC)	$ (17.63)	DJC-3,p25			$ (17.63)	
d.M&S and Fuel Related Sunk Costs	$ 7.70	DJC-13	$ 7.70	OTS Ex. 4SR	$ -	
e. Net Book Value (a+b+c+d)	$ 448.36				$ 375.08	
f.(Market Value)	$ (20.20)	DJC-20,p2	$ (57.70)	DJC-20,pg34 OTS Stmt 4SR	$ (77.90)	
g.PV of Fossil Decommissioning	$ 66.50	DJC-20,p2	$ 24.90	OTS Stmt 2	$ 41.60	
h.PV of Costs Independent of Operation	$ 112.62	DJC-20,p1 Fax Memo Feb 6,98	$ 112.62	OTS Ex. 4SR	$ -	
i. Net Present Value (NPV) in 1999 $ (e+f+g+h)	$ 607.28		$ 268.50	Fax Memo Feb 6,98	$ 338.78	
Discount Rate	7.83%		0.40%		7.43%	OTS Stmt 1,p.8
PUC Jurisdictional Percent	100%					

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	**Docket No. R-00974104**
Duquesne Light Company	:	

CERTIFICATE OF SERVICE

I hereby certify that I am serving the foregoing, the Main Brief of the Office of Trial Staff dated February 9, 1998, either personally, by first class mail, express mail or by fax upon the persons addressed below:

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Dated: February 9, 1998
R-00974104

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PA PUBLIC UTILITY COMMISSION
PROTHONOTARY'S OFFICE

James J. McNulty
Office of the Prothonotary
Pennsylvania Public Utility Commission
North Office Building
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Harrisburg, PA 17105-3265

Re: Duquesne Light Company
Application for Approval of a Restructuring
Plan Pursuant to 66 Pa. C.S. § 2806(d)

Dear Mr. McNulty:

Enclosed is an original and nine copies of Duquesne Light Company's Main Brief. I also have enclosed two additional copies and request that your office time-stamp them and return them in the enclosed self-addressed, stamped envelope.

Thank you for your assistance in this matter.

Sincerely,

DOCUMENT FOLDER

John S. Moot
Counsel to
Duquesne Light Company

Enclosure

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	)	
v.	)	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application to Approve Restructuring Plan Pursuant to 66 Pa.C.C. §2806(d)	)	

MAIN BRIEF OF DUQUESNE LIGHT COMPANY

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Dated: February 9, 1998

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

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v.	)	**Docket No. R-00974104**
Duquesne Light Company Application to approve restructuring plan pursuant to 66 Pa. C.S. § 2806(d)	)	

MAIN BRIEF OF DUQUESNE LIGHT COMPANY

Pursuant to the Ninth Interim Order and 52 Pa. Code § 5.501 (1997), Duquesne Light Company ("Duquesne") hereby submits its Main Brief.

I. INTRODUCTION AND SUMMARY OF ARGUMENT

The most divisive and financially significant issue in this case is generation-related stranded costs. The disputes regarding this issue fall into three main categories: (i) the appropriate methodology for quantifying generation-related stranded costs, (ii) proposals to disallow a portion of those costs, and (iii) the appropriate rate methodology for recovering such costs. Duquesne's offer to auction all its generating assets, however, should eliminate most disputes regarding the quantification of stranded costs and the rate methodology for recovering them. If that offer is accepted, the only remaining, significant dispute would be over proposals to disallow a portion of such costs.

1. The proper quantification of stranded costs turns on a proper assessment of the fair market value of Duquesne's generating assets. All parties agree that the best valuation method is an auction. DLC St. 1-R at 7-11. The central dispute, however, has been one of timing: Duquesne proposed a valuation in 2001-2003 using market evidence, including an auction; the Office of Consumer Advocate ("OCA") and Duquesne Industrial Intervenors ("DII") insisted instead that a valuation must be made today and offered computer forecasts for that purpose. In rejoinder testimony, Duquesne ended this dispute by agreeing to auction all its generating assets today if the Commission finds, as these parties claim, that the Electricity Generation Customer Choice and Competition Act (the "Act") requires that the valuation be made today. DLC St. 1-Rej. at 1. This offer, if accepted, should eliminate the generation valuation dispute.

Consequently, this case is unlike the PECO Energy Restructuring Proceeding, where an auction was not offered and the Commission instead relied on computer forecasts of market prices. Application of PECO Energy Company for Approval of its Restructuring Plan, Docket Nos. R-00973953 & P-00971265, Opinion and Order, slip op. at 82-90 (entered Dec. 23, 1997) ("PECO Energy"). That exercise, by the Commission's own admission, "involve[d] 30+ year projections of every important variable in the business, including electricity prices (expressed on an hourly basis), customer consumption and demand, the hourly output of all

[PECO's] generating plants, and the O&M and capital costs." PECO Energy, slip op. at 82. In this case, the common thread of all Duquesne's proposals has been that a market-based valuation is superior to such computer simulations and, in fact, is the only method that can meaningfully satisfy the "known and measurable" standard. DLC St. 1 at 14; DLC St. 3 at 6. To be sure, the Commission in PECO Energy had no choice but to rely on such computer simulations; however, tellingly, it acknowledged (on a related issue) that "[f]uture energy costs are inherently not 'known and measurable' at this point in time." Restructuring Reconsideration Order, Docket Nos. R-00973953 & P-00971265, slip op. at 9 (entered Jan. 16, 1998). That conclusion directly supports Duquesne's market-based approach in this case.

One further point regarding valuation merits discussion here. This case involves Duquesne's "stand alone" restructuring plan, not the joint restructuring plan filed by Duquesne and Allegheny Energy, Inc. in Docket No. A-110150F0015. In that proceeding, the merging companies have proposed market-based valuation methods, rather than computer simulations, but have not offered an auction of all their Pennsylvania-jurisdictional generating assets. The APS/DLC joint proposal, however, is not at issue in this case; thus, the Presiding Judge should make findings here regarding Duquesne's stand-alone valuation proposal, not the joint proposal. Duquesne fully expects that the merger will be approved by all necessary regulatory agencies, and that it will thereafter be consummated; however, it is critical that the

Presiding Judge make findings here regarding Duquesne's stand alone proposal that would survive should the merger not occur. This will ensure that a customer choice plan is in place for Duquesne's customers under all circumstances.

2. The second major issue is the OCA and DII proposals to disallow (they call it "sharing") a portion of Duquesne's stranded costs. According to them Section 2804(13) implies that stranded generation costs should not be recovered in full from customers, given that it mandates recovery of only a "just and reasonable" level of stranded costs. See, e.g., OCA St. 1 at 41; DII St. 1 at 18.

The OCA and DII proposals should be rejected because there is no support for them in the Act. The sole consideration set forth in the Act regarding the level of stranded cost recovery is mitigation. 66 Pa.C.S. § 2808(c)(4). Yet neither OCA nor DII has contended that Duquesne's mitigation efforts were inadequate (DLC St. 1-R at 18); consequently, there is no basis for any disallowance of stranded costs. See PECO Energy, slip op. at 101 ("allowing PECO full recovery of its actual stranded costs"). Moreover, these sharing proposals, if adopted, would violate federal and state law. The proposals would disallow between $400 and $700 million in costs (DLC St. 3-R at 14) and "would severely damage the financial integrity of the Company." DLC St. 2-R at 45. Consequently, as Mr. Schnitzer explained (DLC St. 3-R at 38-42), the proposals must fail under Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989). Remarkably, the OCA and DII failed to rebut Mr. Schnitzer (OCA

St. 1-S at 8-9; DII St. 1-S at 7-14) and failed even to consider the financial impact of their proposals on Duquesne. There is simply no lawful basis upon which the proposals can be approved.

3. The final issue regarding stranded costs is the appropriate recovery mechanism. In its case-in-chief, Duquesne proposed to recover stranded costs pursuant to Section 2804(4)(v), which provides that "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 . . . ." 66 Pa.C.S. §2804(4)(v). Duquesne proposed to charge capped rates until approximately 2001-2003, at which time a final valuation of Duquesne's generation would be conducted using market evidence. The resulting market values would determine whether Duquesne could cease collecting a CTC prior to the year 2005.

Several intervenors, particularly the OCA and HSS, disagreed with this approach. Their principal objections were that (i) customers should receive rate reductions immediately, (ii) Duquesne's mechanism for measuring "excess earnings" (the ROE "spillover" proposal) was flawed, and (iii) Duquesne's proposal to use a Request for Proposals ("RFP") to adjust CTCs annually was flawed. See generally OCA St. 1; HSS St. 1. While other concerns were expressed, these are the key issues that must be decided if Duquesne's proposal to conduct a final valuation in 2001-

2003 is accepted. If, however, an immediate auction is ordered, these issues are largely mooted and Duquesne would not oppose using the general recovery methodology adopted in PECO Energy. This latter point is discussed in more detail in Section IV.

II. PHASE-IN OF CUSTOMER CHOICE

A. Method of Customer Selection

There are three main disputes regarding customer selection. The first is OCA and DII assertions that Duquesne should have adopted a "first-come, first-served" approach. OCA St. 5 at 57; DII St. 1 at 60. These assertions are misleading. Duquesne has used first-come, first-served principles; it simply has not adopted a pure first-come, first-served approach, and for good reason. Under Duquesne's plan, residential and small-commercial customers are grouped by geographic area and, within those areas, customers have first-come, first-served rights when their area is phased in. DLC St. 6-R at 9. This promotes an orderly, rather than a random, transition to customer choice for small customers, while also using the first-come, first-served method. Id. at 3; DLC St. 6-R at 7-8. Industrial and larger commercial customers are phased-in by "market segment," with the segments that participated most heavily in the pilot program going first. DLC St. 6 at 4. This aspect of the plan has two key benefits. First, it uses the results of the first-come, first-served pilot enrollment, such that the market segments that demonstrated the most interest in

choice will have the first opportunity for it during the transition period. DLC St. 6 at 4. Second, it eliminates potential disadvantages within market segments that an open enrollment would create, with certain competitors having choice and others not (because of oversubscription). DLC St. 6-R at 8. In sum, Duquesne's proposal is superior to a pure "first-come, first-served" method because it (i) "prevent[s] competitive disadvantages among similarly situated customers within a customer class," 66 Pa.C.S. § 2806(b)(4), rather than blithely assuming that a pure first-come, first-served approach will do that, and (ii) builds on the experience gained from the pilot program (DLC St. 6 at 4), rather than establishing a selection process that ignores those results.[1]

The second issue is the Pennsylvania Retailers Association's ("PRA") proposal that 33% of the load of all "large commercial" customers receive access during all three years of the transition period. PRA St. 1 at 6. This is a special "deal" for large commercial customers that is incompatible with the Act. The Act orders a phase-in of customer choice; that, quite obviously, suggests a concern over the administrability of an immediate phase-in of all customers. Such a concern is well-grounded and also applies to the process proposed by PRA, which plainly

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[1] Duquesne notes that, while PECO Energy adopts a pure first-come, first-served approach (slip op. at 47), no similar proposal was made in that case. Rather, PECO had proposed random selection for residential customers and first-come, first-served for commercial and industrial customers. Id.

"present[s] excessive difficulties in account administration and billing, triggering extraordinary volumes of customer contacts and imposing unnecessary complexity and inconvenience on those customers." DLC St. 6 at 5. In short, it is not, for practicable purposes, any different than an immediate phase-in, something proscribed by the Act.

The third dispute is over suggestions that the enrollment process be structured to ensure that 33% of customers switch suppliers during each phase. MAPSA St. 1 at 62. This is contrary to the Section 2806(b)(1)-(3), which provides that a "maximum of 33% . . . shall have the opportunity for direct access" during each phase-in period. (Emphasis added.) Nothing in the Act or PECO Energy suggests that enrollment must be structured, and continue, "until" 33% select another supplier. See PECO Energy, slip op. at 47-48. Duquesne's proposal to offer choice to 33% should be accepted.

B. Timetable for Phase-In

Several witnesses contend that the timetable for customer choice should be as follows: (i) 33% of customers receive choice on January 1, 1999, (ii) 33% of customers receive choice on January 2, 1999, and (iii) 33% of customers receive choice on January 2, 2000. DII St. 1 at 61; Environ. St. 2 at 44. The PECO Energy order adopts this approach as well (slip op. at 48). Duquesne opposes this

proposal as based on a "distorted interpretation of the [Act]" (DLC St. 6-R at 10); however, we recognize that PECO Energy may control this issue.

III. TRANSMISSION AND DISTRIBUTION RATES; UNBUNDLING ISSUES

A. Introduction

There are three types of disputes addressed in this section. The first is the appropriate "functionalization" of costs among generation, transmission and distribution, including proposals that, while of a different name (e.g., "realized rates of return"), have the effect of shifting costs between functions. The second is the appropriate treatment of FERC-jurisdictional ancillary services. The third is a proposal to create new rate classes.

B. 1996 Test Year Cost of Service

Duquesne is not aware of any party that has questioned the test year cost of service study presented by Mr. O'Brien, including the pro forma adjustments to test year amounts. DLC St. 3. The only disputes relate to the functionalization of those costs among generation, transmission and distribution. The proposals consistently have the effect of moving costs out of transmission/distribution and into the generation function, thereby reducing the regulated rates paid by the constituents of the intervenors.

The prime example is Mr. Reising (Enron), who takes issue with several discrete items, each time suggesting that they be allocated to the generation function. The first is FERC Accounts 908 (customer assistance expense) and 909 (informational and instructional expense). Enron St. 2 at 8-9. Yet Enron's own exhibit shows that these accounts relate to "providing instruction or assistance to customers, the object of which is to encourage safe, efficient and economic use of the utility's service" and further "to utilize their electric equipment safely and economically." Enron Cross. Exam. Ex. 1. These plainly are functions that the EDC must continue to provide its customers (DLC St. 5-R at 27-28) and, indeed, a large portion of the costs in Account 908 are included in the rates for universal service. Tr. 799. The second proposed adjustment was that a portion of uncollectible accounts expense be allocated to generation. Enron St. 2 at 9-10. This clearly is not fair to Duquesne, as Mr. Lahtinen explained: "[Mr. Reising's] analysis is flawed because he ignores the fact that under the Competition Act, Duquesne continues to be the supplier of last resort during the transition period while competing suppliers can choose who they serve. This means Enron and other suppliers are likely to serve those customers with a much lower risk of payment default, leaving them to be served by Duquesne." DLC St. 5-R at 29. Finally, it appears that both Enron's proposed adjustments were rejected in PECO Energy, slip op. at 61.

Mr. Reising also submitted an alternative cost of service "study" to replace Duquesne's study (Enron Ex. PDR-3), but it was a flimsy, four-page study that was seriously flawed. First, his cost of service spreadsheet was riddled with "circular references," which standard computer manuals state are "almost always an error, and you should correct it immediately." DLC St. 5-R at 30-31 (quoting Windows manual). But instead of correcting it, Mr. Reising simply claimed that it is an "issue that could have been dealt with through discovery or other protocol." Enron St. 2.1 at 3. Mr. Reising has it backwards: it was his spreadsheets that he failed to correct; it was not Duquesne's responsibility to do so. Second, the study contained other serious errors, such as overallocating costs to Duquesne's only wholesale customer by over 2,500% ($25 million instead of $900,000) and omitting $29 million in revenues from rate class GL. DLC St. 5-R at 31. Finally, Mr. Reising apparently submitted the same cost of service methodology in PECO Energy (Enron St. 2.1 at 3) and the Commission declined to adopt it. PECO Energy, slip op. at 59-61. It should be rejected here as well.

C. Required v. Realized Rates of Return

The question addressed here is whether transmission and distribution rates should be set on a traditional cost-of-service basis. That is the approach proposed by Duquesne, using the traditional three steps. First, Duquesne computed a functionalized revenue requirement for the transmission and distribution functions,

using the rate of return supported by Messrs. Clayton and Makholm. DLC St. 2; DLC St. 4; DLC St. 12. Second, the functionalized revenue requirements were allocated to customer classes as follows. For distribution, demand costs were allocated to classes on the basis of noncoincident peak demands and customer costs were allocated on the basis of the number of customers. DLC St. 5 at 17. This methodology was "consistent with the approach taken by Duquesne in its most recent base rate proceeding." Id. For transmission, costs were allocated to classes on the basis of coincident peak demands, which is consistent with FERC policy. Id. at 16. Third, using these allocated revenue requirements, transmission and distribution rates for each class were then designed. Id. at 47-51.

Several parties object to this approach because it sets transmission and distribution rates on the basis of "required" returns. OSBA St. 1 at 6-7; OCA St. 4-S at 6; DII St. 1 at 42; Enron St. 2.1 at 6. The problem, according to these parties, is that this effectively "shifts costs" in violation of the Act or is a "request for a rate increase." DII St. 1 at 42; Enron St. 2.1 at 6. These parties propose instead to calculate transmission and distribution rates using a "realized" rate of return, which means that the return that Duquesne is presently earning from each rate class will be used to set transmission and distribution rates.

The purpose of these proposals is to shift costs away from transmission and distribution, thereby lowering rates for these services. This occurs because

Duquesne's total revenue requirement cannot fit within the rate cap established by the Act and, hence, the "realized" rates of return for each class are less than the required rates of return. DLC St. 5 at 29-30. Consequently, these parties can lower transmission and distribution rates by using realized, rather than required, rates of return. DLC St. 5-R at 35.

These proposals must fail because this is not how regulated rates are set. They are set to recover the required rate of return. That is how transmission and distribution costs were allocated and recovered in Duquesne's last rate case. DLC St. 5-R at 37. That is how transmission and distribution rates were set in Duquesne's pilot proceeding. Id. at 36. That is how transmission rates were set in Duquesne's FERC filing. Id.[2] Finally, no party has suggested, much less demonstrated, that the T&D revenue requirements proposed by Duquesne are higher than the T&D revenue requirements approved in Duquesne's last rate case (1987); hence, there is no basis for the claim that the Act is violated.

Finally, contrary to the intervenors' arguments, there is no possibility of cost-shifting under Duquesne's proposal. Under Mr. Lahtinen's approach, "total unbundled charges will exactly equal bundled charges at current rates based on 1996

[2] The Commission is precluded by federal law from setting rates that fail to recover the FERC-prescribed transmission rates. Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988).

sales" (DLC St. 5 at 30); indeed, Exhibit No. JAL-9 demonstrates this for every class and no party has disputed this. In fact, the "cost shifting" argument is just a smoke screen. The intervenor proposals have nothing to do with a concern over shifts between classes; their key objective, as indicated, is to shift costs between functions. If successful, their constituents will have the best of both worlds: market rates for power and noncompensatory transmission and distribution rates.[3] Their proposals should be rejected and Duquesne be permitted to set T&D rates on a traditional, cost of service basis.

D. Distribution Losses

There is no longer any dispute regarding distribution losses. Duquesne has agreed to "unbundle" losses so that customers can procure them from alternate suppliers. DLC St. 5-R at 21-22. Consequently, a portion of the embedded costs allocated to losses will become potentially stranded and, hence, must be included in the CTC. Id. at 22. The OCA agrees that stranded costs associated with losses should be included in the CTC. OCA St. 4-S at 3-4.

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[3] On this latter point, Duquesne notes that other companies may have designed T&D rates on the basis of realized, rather than required, returns because, unlike Duquesne, they had recent base rate proceedings and thus the difference between realized and required rates of return may be small, if any. By contrast, Duquesne has not had a base rate proceeding since 1987. Tr. 715.

E. Ancillary Services

Few questions have caused more confusion than the treatment of ancillary services. With one exception,[4] all ancillary services are provided by generating units and each is "necessary to maintain the integrity of the transmission system" in an open access regime. Order No. 888, FERC Stats. & Regs. [Regulations and Preambles 1991-1996] ¶ 31,036, at 31,703 (1996). In Order No. 888, the FERC ruled that all public utilities must offer these services to direct access customers at regulated rates. Id. The FERC also distinguished between services that could only be offered by the host public utility and others that could be competitively procured, assuming that was permitted by prevailing regional reliability rules. Id. at 31,715-716; DLC St. 7 at 13-14. Duquesne has complied with Order 888 by filing cost-based ancillary service rates with the FERC. Duquesne Light Co., FERC Docket No. OA96-56-000.[5]

Two main questions have arisen regarding ancillary services. The first is whether Duquesne should allow its customers to procure all these services

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[4] The exception is "scheduling" service, which is the function of programming an energy management system to accept the projected deliveries by suppliers of generation to the Duquesne control area; the costs associated with this service are primarily labor and control center facilities. DLC St. 5 at 20.

[5] These rates have been put in effect on an interim basis pending approval by FERC of a settlement. The settlement is on the FERC agenda for February 11, 1998.

from alternative suppliers. That is not, however, a question for this Commission. The FERC has determined which services Duquesne must provide and which services can, consistent with regional rules, be supplied by others. Order No. 888 at 31,715-716; DLC St. 7 at 13-14. At present, Duquesne's regional reliability council, ECAR, imposes significant restrictions on when many of these services can be competitively procured, if at all. DLC St. 7 at 13-14; DLC St. 5-R at 19. Thus, as Mr. Lahtinen explained, the intervenors' "complaints are with ECAR, not with Duquesne. Duquesne does not set the rules; it follows them." DLC St. 5-R at 19. The issue therefore must be addressed by FERC or ECAR, not by this Commission.

The second (and closely related) question is whether, for ratemaking purposes, these services should be (i) treated like transmission and distribution, and thereby purchased from Duquesne at regulated rates, or (ii) treated like generation, and thereby competitively procured in the market, with the stranded portion being recovered through the CTC. The answer is that it depends on the service. If, as discussed above, the FERC and ECAR permit suppliers to provide a service themselves, it should be treated just like generation and any stranded costs associated therewith should be recovered in the CTC. DLC St. 5-R at 19. If these bodies require that only Duquesne provide a service, it should be treated the same as transmission/distribution and customers will pay Duquesne a FERC-approved, cost-

based rate for the service. Id.[6] It is that simple and all the arguments to the contrary either (i) inadvertently confuse the issue by treating all such services homogeneously, or (ii) intentionally do so with the clear, and unlawful, purpose of eliminating Duquesne's ability to recover the stranded portion of these costs in the CTC. Duquesne's proposal, as explained by Mr. Lahtinen (id.), should be adopted.

F. Voltage-Differentiated Rates

Enron has proposed creating new customer classes that are differentiated by the voltage level at which a customer is served. Enron St. 2 at 26. This proposal should be rejected because it shifts costs between classes (DLC St. 5-R at 32-34), which Enron does not dispute. Enron St. 2.1 at 5.

G. Other Issues

N/A.

H. Conclusion

The allocated cost of service study submitted by Mr. Lahtinen (DLC St. 5; DLC St. 5-R) should be accepted.

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[6] The FERC has jurisdiction over unbundled retail transmission and ancillary service rates. Order No. 888 at 31,781. Consistent therewith, Duquesne's rates for pilot customers were filed with, and accepted by, the FERC. Allegheny Power Serv. Corp., 81 FERC ¶61, 271 (1997).

IV. TRANSITION OR STRANDED COSTS

A. Overview of Stranded Cost Valuation and Recovery Approaches

1. Introduction

The pivotal issue in this case is whether to accept Duquesne's offer to auction its generating assets today. That offer, if accepted, should resolve most disputes regarding the quantification of stranded costs and the methodology for recovering them. If that offer is not accepted, the Judge must chose between sharply different market valuation and stranded cost recovery proposals.

2. Duquesne's Approach

(a) Market Based Valuation

The fundamental premise of Duquesne's approach to stranded cost recovery is that the market, not career forecasters, should set the value of Duquesne's generating assets. No party has presented a compelling argument to rebut this premise and, indeed, most parties agree with it. DLC St. 1-R at 7-11. A few excerpts from opposing witnesses is instructive:

> **Mr. Metro (OTS):** "In my opinion, Duquesne's market value approach to stranded costs is superior to a 'regulator administered' approach. . . I believe that any utility's stranded cost claim is in error if it is based on 30 year market rate projections." OTS St. 4 at 15-16.

> **Mr. Seiple (Pittsburgh):** "Mr. Schnitzer wisely asserts that 'a market-based determination of stranded costs is inherently superior to an administrative determination.' I strongly agree with Mr. Schnitzer . . . ." Pitts. St. 1 at 6.

Mr. Russell (MAPSA): "One could rely upon experts to project future market prices, but, as noted in the Company's testimony, experts have proven remarkably unprescient in predicting future energy prices." MAPSA St. 1 at 6.

Dr. Weisenmiller (HSS): "I agree with Mr. Schnitzer that an administrative determination of stranded costs can lead to a complex proceeding that is essentially 'the battle of the experts' and 'the battle of the models.'" HSS St. 1 at 118.

The principal dispute therefore has not been over the premise that administrative "forecasts" are inherently unreliable.[7] Instead, the disputes have centered on the market valuation method and the timing of that valuation. In particular, the essential criticism of Duquesne's initial plan was that (i) an auction of generation is the best, and perhaps only, market-based mechanism that can satisfy the known and measurable standard (see HSS St. 1-S at 3), and (ii) whatever valuation method is used, it must be employed today, not in 2001-2003 (as proposed by Duquesne). OCA St. 1 at 7; DII St. 1 at 26; HSS St. 1-S at 4. Duquesne's rebuttal testimony eliminated the first dispute by offering to auction all its generation, although Duquesne continued to assert that such a valuation need not, and

[7] Even the OCA and DII, the parties sponsoring computer simulations, do not claim that those methods can reliably predict market prices. Rather, as OCA witness Kahal stated, "I concur with Company witnesses that performing market valuations on long-lived plants is a difficult undertaking." OCA St. 1 at 12; see also DII St. 1 at 26 ("I recognize that there is uncertainty with respect to future market prices"). Indeed, both witnesses conceded that an auction is superior to a computer forecast. DLC Ex. DDM-1 at 2, 5.

indeed should not, be conducted today. DLC St. 1-S at 2. Thus, the second dispute still remained; and some intervenors contended in surrebuttal testimony that any such auction must be held today. OCA St. 1-S at 5; HSS St. 1-S at 4. In rejoinder testimony, Duquesne agreed to eliminate that dispute through its offer to auction generation today. DLC St. 1-Rej.[8]

(b) Auction Implementation Issues

If Duquesne's auction offer is accepted, there are three main implementation issues to be addressed. The first is the process and rules by which the auction is conducted. Duquesne commits to file proposed procedures and rules within 90 days of the date of entry of a Commission order accepting Duquesne's auction proposal. All interested parties may comment on them at that time.

The second is the establishment of an "interim" CTC that takes effect January 1, 1999. An interim CTC is necessary because it is unlikely that the auction will be completed by that time. To simplify the issue, Duquesne proposes to apply

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[8] Duquesne continues to believe, however, that (i) market methods other than an auction can meet the known and measurable standard, and (ii) it is preferable to conduct a final valuation in 2001-2003 when markets are more fully developed. DLC St. 1-Rej. at 1-2; DLC St. 3-R at 16-18. Other parties concur that the valuation should be deferred until later in the transition period. DLC Ex. DDM-1 at 14.

the same rates (and credits) approved in the pilot program for customers electing direct access during this interim period.[9]

The third is the method for calculating a "permanent" CTC using market values produced by the auction. If an immediate auction is ordered, Duquesne is willing to waive application of Section 2804(4)(v) and adopt the general approach used in PECO Energy, provided that the following two conditions are met. First, Duquesne is permitted to fully recover (e.g., with no "sharing" and a compensatory return on equity) its stranded costs, as established by the market values produced by the auction. Second, Duquesne's continuing obligation to serve at capped rates must be addressed. (Duquesne's concerns on this issue are discussed at DLC St. 1-R at 13-17.) Duquesne commits to submit a proposal to address its continuing obligation to serve at the same time that it files a final CTC calculation using market values produced by the auction.

3. Intervenor Approaches

The intervenor approaches differ in two main respects from Duquesne's proposals. The first is proposals to calculate market value using computer simulations (advocated by OCA and DII). Duquesne strongly objects to this

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[9] Also consistent with the pilot program, Duquesne would defer revenue losses associated with the market and customer participation credits for collection in the final CTC.

approach, as explained above; however, if the Judge believes that a finding is required as to market forecasts, the Judge should adopt the forecast submitted by Duquesne, which relies on market data to the maximum extent possible. The second is proposals for immediate rate reductions (OCA and HSS). These rate reductions may be attractive for the OCA and HSS, but they are proscribed by Section 2804(4)(v), which states that "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 . . . ." 66 Pa.C.S. § 2804(4)(v) (emphasis added). Each of these issues is discussed in more detail in subsections IV.B.3 and IV.F.3, respectively.

4. Conclusion

Many of the key disputed issues will be eliminated if Duquesne's offer of an immediate auction is accepted, which all parties agree is the best valuation method. If this offer is not accepted, the Judge should accept Duquesne's proposal to conduct a final valuation in 2001-2003 and approve a stranded cost recovery plan pursuant to Section 2804(4)(v). The final valuation proposal is discussed in more detail in subsection IV.B.1, while the §2804(4)(v) recovery plan is discussed in subsection IV.F.3(a).

B. Generation-Related Stranded Costs (Recovery Pursuant to Section 2808(3))

1. Introduction

There are three types of issues discussed in this section. The first is "net book value." The second is Duquesne's proposal to determine the market value of its plants in 2001-2003 (the "final valuation" proposal). The third is competing forecasts of market prices and operating costs.

2. Net Book Value

(a) Total Net Book Value

As Duquesne Exhibit DJC-10 illustrates, there is general agreement among Duquesne, OCA and DII on the Net Book Value of Generation Plant. See also DLC St. 3-R at 10-11. The only material difference is with the OTS, which, unlike OCA and DII, disallows recovery of Phillips and Brunot Island costs.

(b) Treatment of Beaver Valley 2 Lease Costs

Duquesne, OCA, DII and OTS all agree that Duquesne should be permitted to recover the costs of the lease payments for Beaver Valley Unit No. 2.

DLC Ex. DJC-10.[10] While the parties state these costs on differing bases, Exhibit DJC-10 restates the values on a consistent basis (i.e., present value net of tax[11]).

(c) Recovery of Phillips and Brunot Island Costs

In 1986, Duquesne placed into "cold reserve" and removed from rate base the Phillips Station and certain of the Brunot Island units. DLC St. 2 at 6. Duquesne is requesting stranded cost recovery for these assets. DLC St. 4 at 14-15. The OCA and DII do not oppose the request. DLC Ex. DJC-10. The OTS, however, argues that since the units were rendered uneconomic in 1986 they were not stranded by the Customer Choice Act; hence, OTS argues, they cannot qualify as stranded costs. OTS St. 4 at 25. HSS also contests recovery of these costs. HSS St. 1 at 106.

These arguments are not compelling. The OTS is mistaken in suggesting that the past economics of these units is relevant; the point is that the Act will render them stranded once and for all. The OTS and HSS adjustments also conflict with the past ratemaking treatment of these assets. Over the last ten years,

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[10] Duquesne entered into a sale-leaseback transaction that removed the BV2 asset from its books. DLC St. 2 at 9; DLC St. 2-R at 57.

[11] Exhibit DJC-10 restates the calculations of the OCA, DII and OTS on a consistent basis using a present value, net of tax calculation. A "net of tax" calculation – which, in effect, calculates the cash that Duquesne would have to receive today to recover its stranded costs, including the related tax effects – is consistent with the method used in the PECO Energy, Restructuring Reconsideration Order (pages 24-25) ("PECO should exclude the tax gross up by multiplying the resulting present value by .587 to reflect PECO's tax rate of 41.3%").

Duquesne has sought to reactivate these plants in a manner that would benefit ratepayers (Tr. 109-112), including reaching an agreement with General Public Utilities ("GPU") to reactivate them in support of a 500 MW, 20-year sale. DLC St. 1 at 26. The Commission approved this transaction (over the objection of the OTS), finding that it would produce over $300 million in present value benefits to ratepayers. Id.; Tr. 111; see also HSS Ex. RBW-45. While the transaction ultimately fell through (DLC St. 1 at 26), the point is that the Commission determined that ratepayers, not shareholders, should receive the benefits. Id. It is therefore unfair for these parties now to contend that Duquesne's shareholders, not its ratepayers, should bear the economic detriment now associated with the assets. Id. at 27; DLC St. 2-R at 35.

(d) Conclusion

The Judge should reject the proposed disallowance of Brunot Island and Phillips costs and find that the Net Book Value figure presented by Duquesne is supported by the evidence.

3. Market Value

(a) Introduction

If Duquesne's offer of an immediate auction is not accepted, the Judge must address Duquesne's proposal to conduct a "final valuation"[12] in 2001-2003

[12] This "final" valuation is distinguished from Mr. Schnitzer's "interim" (continued...)

using market evidence (including an auction if so ordered by the Commission). DLC St. 1-R at 11-12. The foundation of this proposal is that (i) computer forecasts of market prices are inherently unreliable, (ii) a market valuation in 2001-2003 will be superior because better market evidence will be available as electric markets mature, (iii) a valuation today is not necessary given that, even under the OCA and DII market price forecasts, Duquesne cannot fully recover its stranded costs until at least 2003, and (iv) given the nature of Duquesne's obligations under the rate cap, a final valuation later in the transition is preferable to a one-time valuation today. DLC St. 1 at 14-18; DLC St. 1-R at 11-17; DLC St. 3 at 12-20; DLC St. 3-R at 15-32, 44-48.

These points notwithstanding, several parties, although not OTS (OTS St. 4 at 12-14), oppose Duquesne's proposal. The OCA and DII urge the Commission to adopt their computer forecasts of market prices. OCA St. 2; DII St. 2. DII rests its claim on the premise that "certainty" – i.e., fixing a total stranded cost number today – is of paramount importance in this case. DII St. 1 at 25. This is an unsustainable position. The Act establishes "known and measurable" as the standard that must be met (66 Pa.C.S. § 2803); it thus elevates accuracy over any

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[12](...continued)
valuation, which was performed to determine how long Duquesne could continue changing currently approved rates pursuant to Section 2804(4)(v). DLC St. 3 at 23.

supposed benefit of "certainty." Indeed, the only thing "certain" about the computer simulations proferred by OCA and DII is that they will inaccurately forecast future market prices. DLC Ex. 1-R at 7-11. Tellingly, DII chose not to rebut the evidence submitted by Duquesne that such forecasts have proven grossly inaccurate, including in Pennsylvania. Compare DLC St. 3 at 6-16 with DII St. 2 at 14.

The OCA's principal objection to a final valuation is that it will not produce immediate "rate reductions" because current rates (per Section 2804) are charged in the meantime. OCA St. 1 at 13; OCA St. 1-S at 4. The OCA has it backwards. The issue here is the soundness of the valuation methodology,[13] not whether it "results" in any particular rate stream. In any event, the supposed importance of rate reductions (OCA St. 1 at 13) cannot be squared with Section 2804(4)(v), which suggests a legislative preference for accelerating stranded cost amortization to end the CTC recovery period early rather than reducing rates now and lengthening the transition period. 66 Pa.C.S. § 2804(4)(v).

HSS opposes the final valuation because it argues Duquesne has no stranded costs. HSS St. 1 at 14. HSS stands alone on this issue: every other party that considered the matter in detail estimates that Duquesne has at least $1 billion in

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[13] Tellingly, the OCA, like DII, does not assert that its market price projections are sufficiently reliable to meet that standard (see OCA St. 2); rather, its claim is that the forecasts provide a "consistent set of planning assumptions" for all Pennsylvania utilities. OCA St. 2-S at 1.

stranded costs. OCA Ex. MIK-1 at 1; DII Ex. SJB-2; OTS Ex. 4SR, Sch. 1. Using those estimates, Duquesne recalculated the date for its final valuation (DLC St. 2-R at 4-5); hence, the final valuation is no longer even based on Duquesne's market price projections. Moreover, the evidentiary presentation that supports HSS's claim is riddled with inconsistencies.[14] Finally, the relief HSS really seeks (a forced divestiture) is proscribed by the Act.[15]

(b) Market Price Projections

The market price projections discussed below need only be addressed if the Judge determines that a one-time forecast of stranded costs must be made today.[16]

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[14] The following are two noteworthy examples. HSS devotes nearly one hundred pages of testimony to attacking Duquesne's market evidence (HSS St. 1; HSS St. 1-S), yet fails to spend a single sentence critiquing the OCA's market price forecast – which is nearly identical to Duquesne's. DLC St. 3-R at 24. HSS vehemently objects to deferring the final valuation to a panel of experts (HSS St. 1 at 3-5), yet proposes to defer a determination of nuclear decommissioning costs to an expert "auditor." HSS St. 1 at 72-74.

[15] HSS contends that Duquesne cannot recover any stranded costs from ratepayers unless it sells all its generating assets today. HSS St. 1 at 141. That relief is proscribed by the Act. 66 Pa.C.S. § 2804(5). The City of Pittsburgh recognizes that the Commission cannot order such a sale absent Duquesne's consent (Pitts. St. 1 at 18), but suggests that the PUC penalize Duquesne if it does not offer such an immediate auction. Id. at 18-19. This proposal, like the HSS proposal, should be rejected as beyond the Commission's authority.

[16] The exception is that, if the Judge adopts the final valuation proposal, the Judge also should find that the market price forecasts of OCA (or Duquesne) are

(continued...)

(i) Forecasting Methodology

Three witnesses submitted market price forecasts: Mr. Schnitzer (Duquesne), Mr. Smith (OCA) and Mr. Falkenberg (DII). The key methodological difference between the Duquesne and OCA/DII forecasts is that Mr. Schnitzer based his forecasts, wherever possible, on market transactions. Specifically, for the years 1997-2005, Mr. Schnitzer used the results of Duquesne's eight-year RFP. DLC Ex. MMS-4; DLC St. 3 at 32-39; DLC St. 2-R at 12.[17] This is the only market evidence of power prices during that period.[18] For the years beyond 2005, no comparable market evidence was available and therefore Mr. Schnitzer based his forecast (for those years) on the cost of new capacity; the cost of new capacity serves as "cap" on market prices, although prices may well be below the cap. DLC St. 3 at 25-37.[19] In estimating the cost of new construction (a combined cycle unit), he provided a range

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[16](...continued)
reasonable for the more narrow purpose of setting the date for the final valuation.

[17] That auction produced 11 bids for 1300 MW of firm power to be sold by Duquesne for an eight-year period. DLC St. 7 at 9.

[18] The evidence is consistent with historic market price data for power sales in Duquesne's area. Compare DLC St. 7 at 9 with id. at 3-6 and DLC St. 5 at 74-76.

[19] The cost of new capacity provides a "ceiling" (or cap) on the prices existing producers can charge "because if market prices were to exceed the ceiling it would be economic for new entrants to contest the market at those prices." DLC St. 3 at 25.

("low" and "high") of prices and, again, relied on actual market data as much as possible. Id. at 26-27 (using market data for gas and gas transportation costs).

The Judge should therefore find that Mr. Schnitzer's forecasts are inherently superior to the OCA/DII methods, given that he used market evidence wherever possible.[20] (Notably, even despite the methodological differences, the results of Mr. Schnitzer's low price forecast and Mr. Smith's forecast are nearly identical. See DLC St. 3-R at 24.)

(ii) Input Assumptions

There are three disputed "input assumptions" that merit discussion here. The first is Mr. Falkenberg's (DII) assumption that ECAR utilities will begin constructing new generating capacity immediately to meet an assumed 15% reserve margin requirement. DII St. 2 at 21; DLC St. 3-R at 27.[21] There is no evidence in the record to support Mr. Falkenberg's assumption. Even he does not offer evidence to support it; rather, he simply asserts, without explanation, that "I add capacity to meet a 15% reserve margin requirement for ECAR." DII St. 2 at 21. But it is

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[20] As indicated by Mr. Marshall, Duquesne is not recommending the use of estimates of market prices, including Duquesne's own estimate, for purposes of making a one-time determination of stranded costs. Tr. 75-79.

[21] This assumption causes his market price to escalate sharply in the early years of the transition period (when the net present value of such an adjustment is the greatest). DII Ex. RJF-5b; DLC St. 3-R at 26-27.

undisputed that there is no such reserve margin requirement in ECAR. DLC St. 9-R at 2. Moreover, even apart from whether there is any such "requirement," ECAR predicts that it has ample capacity through at least the year 2005. DLC St. 9 at 9. This is borne out by the results of Duquesne's recent power sale auction (DLC St. 3-R at 27) and by recent capacity purchases by Duquesne that reflect the current excess capacity situation in ECAR. DLC St. 7 at 5-6. In sum, there is no support for Mr. Falkenberg's assumption regarding capacity additions.[22]

The second disputed assumption relates to Mr. Schnitzer's use of market prices from Duquesne's eight-year power sale auction. While Mr. Smith did not criticize this assumption[23] and Mr. Falkenberg devoted only a single sentence to it,[24] HSS and MAPSA attempt to pick apart every aspect of the RFP. MAPSA St. 1

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[22] The OCA's Mr. Smith also makes an assumption that ECAR will add capacity pursuant to a set reserve margin, although his assumption (8%) is far less aggressive. OCA St. 2. (His assumption produces an arbitrary "spike" in prices in the year 2003. OCA Ex. DCS-4.) For the same reasons as discussed above, such an "assumption" regarding capacity rules that do not today exist cannot possibly meet the known and measurable standard.

[23] This is not surprising given that, with one notable exception, his own forecast closely tracks the RFP results. DLC St. 3-R at 24. The one exception, as indicated in the previous footnote, is his assumption regarding the addition of new capacity in 2003.

[24] Mr. Falkenberg referred to the RFP results as reflecting "lower market prices" that do not "provide a realistic assessment of market prices." DII St. 2 at 14. This comment is circular, just like his assumption of higher prices in the early transition years based on his assumption regarding the addition of new capacity

(continued...)

at 25-29; HSS St. 1 at 24-39. None of these criticisms is valid, as explained in detail by Mr. Lahtinen. DLC St. 5-R at 5-20; DLC Ex. JAL-14; DLC St. 5-Rej. Moreover, the arguments fail for a very simple reason: the prices produced by the RFP are consistent with all the other actual market data (not forecasts) in this case, none of which have the supposed "design defects" of the RFP. DLC St. 7 at 3-6; DLC St. 5 at 74-76. (See Section V.B.1 for further discussion of this point.) What MAPSA and HSS really dislike is the fact that prices are low in ECAR because the region has excess capacity. DLC St. 9 at 9.

The third disputed assumption is Mr. Schnitzer's forecast of the cost of a new combined cycle unit. Mr. Falkenberg devotes considerable effort to attacking this forecast, yet his criticism is academic (and mystifying) given that his own market price forecast for the same period (post 2005) is below Mr. Schnitzer's forecast. DLC St. 3-R at 20. Dr. Weisenmiller also heavily criticized Mr. Schnitzer's forecast, but neglected to criticize either (i) the OCA forecast, which is consistent with Mr. Schnitzer's forecast for the entire period; or (ii) the DII forecast, which is consistent with Mr. Schnitzer's forecast post-2005. Thus, Mr. Schnitzer's forecast hardly stands alone, as Mr. Weisenmiller wrongly suggests. HSS St. 1 at 152.

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[24](...continued)
immediately.

(iii) Results

A depiction of the results of the Schnitzer, Smith and Falkenberg forecasts is provided on page 20 of Mr. Schnitzer's Rebuttal Testimony DLC St. 3-R.

(c) Other Evidence of Market Value

The only other "market" evidence meriting attention is the sale of Duquesne's interest in the Ft. Martin plant. Duquesne agreed in 1995 to sell its share (276 MW) of the plant to a subsidiary of APS at a price significantly above its book value. DLC St. 1 at 26; DLC St. 2 at 10-11. Dr. Weisenmiller (HSS), in particular, focuses on the results of this sale in asserting that Duquesne likely has no stranded costs. HSS St. 1 at 22-24, 39. Yet this assertion is not even consistent with his own deposition, where he conceded that the sale of one unit does not necessarily provide a market value for any other unit. DLC St. 2-R at 55. Moreover, the price bid by APS was based on the type of market price "projections" that he criticizes (HSS St. 1 at 23); moreover, those projections "bear no resemblance to current market conditions." DLC St. 2-R at 55; see also DLC St. 3-R at 27.[25] Indeed, the Ft. Martin sale shows how price forecasts can become outdated in only two years. Id.

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[25] HSS also refers to market assessments provided to Duquesne by third parties. HSS St. 1 at 15-21. HSS fails, however, to note that a range of valuations was provided, including scenarios where the plants had no value. DLC St. 2-R at 54.

(d) Conclusion

The Judge should find that Mr. Schnitzer's low price forecast is the most reliable forecast because it relies, to the extent possible, on actual market data; it does not include unsupported assumptions regarding capacity requirements; and it is virtually identical to Mr. Smith's forecast for all years and to Mr. Falkenberg's forecast post-2005. DLC St. 3-R at 19-27.[26]

4. Other Factors Affecting Market Value/Stranded Costs

As in the preceding section, the matters discussed here must be decided only if an administrative determination of stranded costs is made.

(a) Life Extension

Not content with projecting market prices and operating costs for the life of Duquesne's generating units, the OCA goes one step further and makes projections assuming that Duquesne's coal plants are "life extended" an additional 15 years. OCA St. 1 at 35-38; OCA Ex. MIK-8. Using this adjustment, the OCA's Mr. Kahal creates nearly $200 million in additional market value. OCA St. 1 at 38; DLC St. 3-R at 23-24. Mr. Kahal's adjustment is unsustainable. First, it is not based on a life extension study of Duquesne's units; it is based on studies by other utilities

[26] There are other disagreements with the OCA regarding market value, but these disputes relate to "adjustments" made by Mr. Kahal. These items are discussed in Subsection IV.B.4.

(PECO Energy and APS) in other cases of their plants. OCA St. 1 at 35, 37. These estimates cannot possibly support a "known and measurable" calculation for Duquesne. As the Commission held in PECO Energy (as to fossil decommissioning), such a forecast of "[p]rospective...expenses [and revenues]...without a specific plan to [life extend] a particular plant at a particular time and in particular manner" cannot satisfy the known and measurable standard. PECO Energy, slip op. at 92. Second, OCA's market price witness, Mr. Smith, failed to support the market price projections used by Mr. Kahal for his analysis. OCA Ex. MIK-8 at 6.[27] Third, Mr. Kahal's assumption that current technology will continue to set market prices nearly 40 years from now is "somewhere between silly and reckless," as Mr. Schnitzer testified. DLC St. 3-R at 22.[28] In fact, Mr. Kahal tacitly agreed: "[i]n reality, the Company would defer life extension investment decisions until the years shortly before book retirement date[s] due to the inherent uncertainty of making such decisions this far in advance." OCA St. 1 at 35-36 (emphasis added). In sum,

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[27] Mr. Kahal simply "escalated" Mr. Smith's market price forecast over an additional 20-year period (OCA St. 1 at 37) without any concurrence from Mr. Smith that such a projection was reasonable. Mr. Smith's sponsored market price projections terminate in the year 2015 (OCA Ex. DCS-4), while Mr. Kahal's extend until 2034. OCA Ex. MIK-8 at 6.

[28] Notably, Mr. Smith did not defend such an assumption and neither did Mr. Kahal on surrebuttal. See OCA St. 1-S; OCA St. 2-S.

Duquesne cannot conceive of an adjustment that is less "known and measurable" than Mr. Kahal's life-extension projections.

(b) Plant Shutdowns

Several witnesses suggest that Duquesne should permanently[29] shut down certain generating stations. See OCA St. 1 at 24; HSS St. 1 at 70-71. The issue arises because, under Mr. Schnitzer's low market price forecast, some of Duquesne's units have "negative" operating margins -- i.e., they receive less revenue than it costs to operate them. Compare DLC Ex. DJC-20 at 2 with id. at 18 and id. at 34. While this intuitively supports a shut down decision, it is not a complete analysis. As several Duquesne witnesses explain, there are unavoidable costs (e.g., property taxes and labor costs) that Duquesne will incur even if the plants are shut down. DLC St. 2-R at 13-14; DLC St. 3-R at 11-12; DLC St. 4-R; DLC St. 9-R at 19-22; DLC St. 10-R at 2-7; DLC St. 11-R at 10-16.[30] The OCA's Mr. Kahal did not

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[29] Initially, the OCA proposed a "temporary" shutdown of the Cheswick plant. OCA St. 1 at 24-25. But this "assume[d] that the Cheswick unit can be placed in reserve for free until 2006, at which point it can be reactivated at no cost." DLC St. 3-R at 25 (emphasis added and in original); see also DLC St. 10-R at 2-7. In surrebuttal testimony, Mr. Kahal withdrew the proposal, acknowledging "the Company's legitimate point that there would be shutdown and restart costs (and ongoing caretaker costs) associated with a shutdown." OCA St. 1-S at 13.

[30] Once these costs are taken into account, the only plant that appears to be uneconomic is Elrama; however, that plant is needed for transmission system reliability and cannot be shut down without construction of system enhancements.

(continued...)

contest the accuracy of this evidence, but rather asserted that "there is not adequate time to investigate" it. OCA St. 1-S at 11.[31] In any event, Duquesne has committed to file a detailed study regarding potential plant closures in 1998 and allow "the Commission [to] make the determination of whether any units should be shut down." Compare DLC St. 1-R at 24-25 with OCA St. 1-S at 8; HSS St. 1-S at 36.

(c) Productivity Gains

The OCA proposes to increase the market value of Duquesne's plants by $13 million to reflect estimated "productivity gains." OCA St. 1-S at 14; OCA St. 1 at 29-34. HSS proposes that, in setting any CTC, the Commission should assume cuts in operating and capital expenditures of between 10% and 20%. HSS St. 1 at 64.

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[30](...continued)
DLC St. 9-R at 19-22.

[31] Mr. Kahal also suggested that this evidence constituted a significant change of position from the evidence in Duquesne's case-in-chief. OCA St. 1-S at 11. This fails to recognize that Duquesne's case-in-chief did not propose a "one-time" determination of stranded costs as of January 1, 1999 and, hence, no such calculation was required. Indeed, Duquesne provided only an estimate of stranded costs as of December 31, 2005, which did not show such plants to be uneconomic for the post-2005 period. DLC St. 2-R at 14; DLC Ex. DJC-21. It was only in response to intervenor, including OCA, claims that Duquesne "must" conduct a one-time calculation as of January 1, 1999 that this evidence was introduced. DLC St. 2-R at 14.

Each proposal must fail because it is not based on any study of the efficiencies that could be achieved given Duquesne's particular assets and workforce. OCA St. 1 at 33; HSS St. 1 at 64. Each avoids addressing the significant cost savings and operating improvements already made by Duquesne and the further savings ($25 million annually) projected for the future. DLC St. 1 at 21; DLC St. 10 at 5-6, 9-10; DLC St. 11 at 3-7). Each fails to consider the additional savings ($500 million on a nominal basis) that Duquesne's expects to achieve through the merger. DLC St. 1 at 6; Tr. 564-66. In short, the assumption that substantial additional savings can be achieved has no factual basis, as Duquesne's witnesses explained in detail. DLC St. 10 at 6-7; DLC St. 11 at 5-6; DLC St. 10-R at 9-10; DLC St. 9-R at 12-13.

(d) Costs Independent of Operation

"Costs Independent of Operation" represent costs that are unavoidable if a generating unit is shut down. Costs independent of operation are not, as some intervenors suggest, a novel concept. HSS St. 1-S at 35-36. An obvious example is nuclear decommissioning. Tr. 557. These costs cannot be avoided by shutting down a nuclear plant; indeed, the costs increase (on a net present value basis) the sooner a plant is shut down. DLC Ex. DJC-13. For purposes of illustration, we discuss only two additional categories here. The first is property taxes. Depending on the assessment practices of a given state or locality, the property taxes on a generating

station may, or may not, abate when the plant ceases operation. DLC St. 4-R at 3-4. For example, the Perry nuclear station is located in Ohio, where unlike Pennsylvania, tax assessments continue to apply even if a plant is shut down. Id. at 4. The second category is administrative and general costs. These costs do not decline (or increase) in direct proportion to the number of generating units that are operating. Id. at 2-3; DLC St. 10-R at 5. Thus, shutting down a single plant will allow Duquesne to avoid some, but not nearly all, of the labor and facilities costs that support the generating function of the business. Id.; Tr. 578, 600-602.[32] In sum, there is no real dispute that a significant level of these costs is unavoidable; therefore, if an administrative determination of stranded costs is made, Duquesne's projection of these costs should be included.

(e) Projected Capital Additions and O&M Expense

The HSS proposal regarding an "assumed" level of O&M or capital expenditure reductions was discussed above (in the "productivity gains" section).

(f) Environmental Regulations

All the market price forecasts in this case ignore two recent proposals that, if implemented, would add significant costs to operating Duquesne's generation.

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[32] It is possible, however, that a substantial amount of these costs could be avoided through a full divestiture, which would eliminate the generating function of the business. Tr. 625-26.

The first is the EPA State Implementation Plan ("SIP call"), which would add over $100 million in capital and O&M expense to Duquesne's fossil units. DLC St. 10-R at 8-9. The second is the recent Kyoto conference, where the participating nations agreed to significantly reduce CO_2 emissions. Tr. 937-43. While it is not possible to quantify precisely the impact of such proposals on Duquesne's generation costs, the Judge should recognize that all of the market value estimates are conservative in not taking into account the cost impact of these potential regulations.

(g) Other

N/A

(h) Conclusion

N/A

5. Conclusion

It is not in the interests of ratepayers or shareholders to make one-time predictions of market value over a 40-year period; that should be left to the market and buyers and sellers that bet their own money, not career experts that bet the money of someone else. Tr. 62-63, 400, 403-04. If, however, the Judge determines that a finding as to stranded cost projections must be made, Duquesne's projection should be accepted as the most reliable.

C. Merger Savings

Any issues regarding merger-related synergies are appropriately addressed in the merger docket, not this proceeding.

D. Decommissioning

Mr. LaGuardia submitted detailed, site-specific decommissioning studies for each of Duquesne's generating units. DLC St. 13 and DLC St. 13-R. Mr. LaGuardia manages a firm (TLG Services, Inc.) that bids on and performs decommissioning work for both nuclear and non-nuclear facilities; he is not just an expert witness. Tr. 643-44. The criticisms of his estimates were very few.

1. Nuclear Decommissioning

No intervenor witness submitted a nuclear decommissioning study or criticized Mr. LaGuardia's study in any detail. The main criticism related to the "contingency factor" used by Mr. LaGuardia. The OTS claims that a contingency factor simply adds "an estimate for unknown circumstances on top of what is already an estimate of expenses." OTS St. 2 at 5. By contrast, the OCA would allow a contingency factor, but simply reduce it to 10%, relying on a "proposed" policy statement by the Commission. OCA St. 3 at 19.

The OTS proposal should be rejected because it has no substance. To contend that a contingency factor should be rejected because it represents a "contingency" is simply not enough here. Mr. LaGuardia testified at length during the

hearing that, in his firm's actual experience, contingency factors have proven accurate. Tr. 649-53. Indeed, TLG Services' ability to accurately predict the cost of decommissioning, including contingencies, has been remarkable – falling within approximately 4% for plants already dismantled. DLC St. 13 at 25; Tr. 677-78.[33]

OCA's reliance on a proposed policy statement that was never adopted (DLC St. 13-R at 11-12) is hardly compelling, and that was the only evidence provided in support of its adjustment. OCA St. 3 at 19. Mr. LaGuardia's contingency analysis, by contrast, was not simply a "plug" percentage for all plants, but rather was site specific (DLC St. 13-R at 11) and hence varied for each plant. Tr. 647-49. Finally, Duquesne notes that in PECO Energy the Commission appeared to accept, without adjustment, Mr. LaGuardia's estimate of decommissioning expense. PECO Energy, slip op. at 78.

2. Fossil Decommissioning

In PECO Energy, the Commission held that "[p]rospective fossil decommissioning expenses are not recoverable . . . as a stranded cost, because they

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[33] HSS claims that there is "no established track record . . . [for] large-scale" decommissioning (HSS St. 1 at 74), but ignores the actual experience of TLG in accurately predicting decommissioning costs, including the Shoreham plant. Tr. 677-78. The Environmentalists avoid the issue entirely by stressing that Mr. LaGuardia's estimates in testimony have increased over the years faster than the rate of inflation (Environ. St. 2 at 32-33), when the real issue, of course, is whether his estimates match actual experience, which they do. DLC St. 13 at 25; Tr. 677-78.

are not 'known and measurable' without a specific plan to decommission a particular plant at a particular time and in a particular manner." PECO Energy, slip op. at 92. Duquesne agrees that forecasts of this nature do not meet the "known and measurable" standard; that is the fundamental premise of Duquesne's market-based proposal. However, the issue the Judge must address in this case is whether decommissioning forecasts stand alone in their fallibility; clearly, they do not. A perfect example is Mr. Kahal's "life extension" projection, which reflects, in the words of PECO Energy, "[p]rospective . . . expenses [and revenues] . . . without a specific plan to [life extend] a particular plant at a particular time and in a particular manner." PECO Energy, slip op. at 92. Accordingly, if the Judge finds that PECO Energy controls, the Judge should reject all other cost and market forecasts having the same flaws, particularly the life extension forecasts of the OCA.[34]

E. Regulatory Assets and Liabilities

1. Introduction

The Act defines regulatory assets as "assets or other deferred charges typically recoverable under current regulatory practice." 66 Pa.C.S. § 2803. Most of

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[34] Of course, if all such forecasts are not rejected, there is no basis in law or fact for excluding fossil decommissioning expense. As Mr. LaGuardia testified, fossil plants will be dismantled to conform to safety codes; the only question is when and at what cost. DLC St. 13 at 49-51. On that issue, Mr. LaGuardia is the only witness that provides such an estimate and, hence, his testimony must be accepted.

the parties faithfully apply this standard to Duquesne's claim and recommend approval of the majority of its regulatory assets. DLC Ex. DJC-10. HSS, however, pursues a different course, focusing its analysis instead on whether there is a specific order that specifically approves the deferral and subsequent recovery of each regulatory asset. HSS St. 1 at 87; HSS St. 1-S at 17.[35] That, however, is not the correct standard, as the Act makes clear, and it is the reason that HSS, unlike every other party, has proposed to disallow virtually every regulatory asset. DLC Ex. DJC-10. While this is not surprising (it mirrors HSS' approach to every other issue), it is meritless nonetheless. Consequently, it is unnecessary to respond below to every specific assertion by HSS where that assertion misapplies the statutory standard.[36]

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[35] HSS asserted in surrebuttal testimony that it used this standard because Mr. O'Brien relied on it in his direct testimony. HSS St. 1-S at 17. That is incorrect, as Mr. O'Brien's direct testimony simply stated the obvious – i.e., that an asset is recoverable where there is a specific order permitting a deferral – and never suggested that this was the only circumstance in which recovery was permitted. DLC St. 4 at 5. In fact, Mr. O'Brien's statement specifically referred to SFAS 71 and, as his rejoinder testimony demonstrated, SFAS 71 applies the same standard as the Act, which is that a regulatory asset may be booked where its future recovery is probable, not certain pursuant to a "specific" order. Tr. 567-68; DLC Ex. MKO-3.

[36] It is noteworthy that Duquesne's financial statements, including the regulatory assets, have been audited by the staff of the PaPUC and FERC and by Duquesne's independent auditors. DLC St. 2-R at 16. (A listing of these audits is provided in DLC Ex. DJC-22.)

2. Disputes Regarding Specific Claims

(a) SFAS 109 Deferred Taxes

SFAS 109 deferred taxes were described and supported by Mr. O'Brien (DLC St. 4 at 8-9) and Mr. Clayton (DLC St. 2-R at 19-22). The OTS, OCA and DII support recovery of it. DLC Ex. DJC-10. The FERC Staff reviewed and accepted the entry. DLC St. 2-R at 21. PECO Energy approved the SFAS 109 asset proposed in that case. PECO Energy, slip op. at 68-70. Only HSS opposes it, again applying the wrong standard. The HSS position should be rejected.[37]

(b) Unamortized Debt Costs

Unamortized debt costs were described by Mr. O'Brien (DLC St. 4 at 9-10) and Mr. Clayton (DLC St. 2-R at 22-24).[38] The OTS and OCA support recovery of it. DLC Ex. DJC-10. It appears that PECO Energy approved unamortized debt costs in that case pursuant to the OCA methodology. PECO Energy, slip op. at 76. DII and HSS, however, oppose its recovery. HSS advances the meritless claim that Duquesne should amortize the cost over the life of its generating units, not

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[37] Duquesne notes that the SFAS 109 plant balance (relating to AFUDC) is included in plant, not as a regulatory asset (DLC Ex. DJC-10); this is consistent with the OCA method. OCA Ex. TSC-1.

[38] It is noted that the unamortized debt costs associated with BV2 are included in plant, not as a regulatory asset (DLC Ex. DJC-10), which is consistent with the OCA approach. OCA Ex. TSC-1.

the transition period (HSS St. 1 at 109); this obviously misses the point of Section 2808, which contemplates recovery of stranded costs in a CTC over the transition period. The DII approach is inconsistent with PECO Energy and should be rejected. DLC St. 2-R at 23.

(c) Unamortized Sale/Leaseback Premiums

The unamortized sale/leaseback premiums were described and supported by Mr. O'Brien (DLC St. 4 at 10) and Mr. Clayton (DLC St. 2-R at 24). No party opposes their recovery. (These premiums have been included in plant, not as a regulatory asset (DLC Ex. DJC-10), consistent with the OCA method. OCA Ex. TSC-1.)

(d) Deferred Rate Synchronization Costs

The deferred rate synchronization (or "early window") costs were described and supported by Mr. O'Brien (DLC St. 4 at 10-11) and Mr. Clayton (DLC St. 2-R at 25-26). The OCA and OTS support recovery of them (DLC St. 2-R at 25); the DII proposes that they be stated on a net present value basis, as approved in PECO Energy, slip op. at 74-75. The DII calculation of that number, however, is grossly incorrect. DLC St. 2-R at 25. The restated amount (DLC Ex. DJC-14) should be approved.

(e) Deferred Employee Costs

Deferred employee costs were described and supported by Mr. O'Brien (DLC St. 4 at 11-12) and Mr. Clayton (DLC St. 2-R at 26-27). The OCA and OTS support recovery of them. *DLC Ex. DJC-10.* PECO Energy approved a similar regulatory asset. PECO Energy, slip op. at 74. DII opposes recovery of it, but the argument is meritless. Mr. Kollen contends that the costs simply represent "timing differences," yet all regulatory assets represent "the timing difference between accrual and cash recognition of expenses." DLC St. 2-R at 26; See also DII St. 3 at 17. The asset should be allowed.

(f) Deferred Coal Costs

The deferred coal costs represents fuel costs that, in the past, exceeded "cost caps" in the Company's ECR and were deferred for recovery at a future data when future fuel costs are below those caps. They are described and supported by Mr. O'Brien (DLC St. 4 at 13) and Mr. Clayton (DLC St. 2-R at 27-28). DII contends that the caps at issue are set at "market" levels and, by definition, the Company's fuel costs will never fall below market levels. DII St. 3-S at 17-18. This is not correct. As Mr. Clayton explained in rejoinder testimony, the caps are cost-based caps (Tr. 190-91) and, as Mr. Clayton had previously shown, Duquesne's fuel costs are expected to decline in 2000 to below these caps. DLC St. 2-R at 27-28; DLC Ex. DJC-3 at 3. The asset therefore should be allowed.

(g) Deferred Caretaker Costs

The deferred caretaker costs are the costs incurred in maintaining Brunot Island and Phillips plants in cold storage in the expectation that, in the future, they would become economic. See supra Section IV.B.2(c). The assets are described and supported by Mr. O'Brien (DLC St. 4 at 14-15) and Mr. Clayton (DLC St. 2-R at 32-35). The OCA argues that they cannot be recovered because the units have not been returned to service. OCA St. 3 at 14-15. But this is circular reasoning. The units have not been returned to service precisely because they are uneconomic – i.e., stranded. The asset should be approved for all the same reasons discussed previously in Section IV.B.2(c) regarding these units. DLC St. 2-R at 32-35. (We note that the OCA opposes recovery of these costs, although it did not oppose recovery of the stranded investment associated with the Phillips and BI units. See OCA St. 3 at 14-15; DII St. 3 at 20-21.)

(h) Pre-Accrual of Nuclear Outages

The pre-accrual of nuclear outage costs was described and supported by Mr. O'Brien (DLC St. 4 at 12) and Mr. Clayton (DLC St. 2-R at 29-30). This regulatory asset arises from a change in accounting that was specifically approved by Duquesne's outside auditors and the FERC audit staff. DLC St. 2-R at 29. The OCA opposes the change because it fears that it will result in a double counting of costs. OCA St. 3 at 11. This is not correct because the item has not been included in the

future operating expenses projected in this case. DLC St. 2-R at 29. Thus, if the claim was disallowed, "the Company should increase its operating expenses in the years that outages actually occur." Id. The regulatory asset should be approved.

(i) Transition Costs

The transition costs, which relate to the expense of this restructuring proceeding and pilot program deferrals, were described and supported by Mr. Clayton (DLC St. 2-R at 30).[39] The OCA and OTS do not oppose their recovery. DLC Ex. DJC-10. PECO Energy permitted recovery of similar costs. PECO Energy, slip op. at 93. DII and HSS, however, oppose part and all, respectively, of these costs, but they do not contest any particular expenditures as unjust or unreasonable. The costs should be approved because they were required to be expended to implement the Act. DLC St. 2-R at 30. Indeed, the pilot program deferrals were specifically authorized by the Commission in its August 29, 1997 Pilot Program Order. Opinion and Order on Pilot Program Implementation, Docket No. P-00971175 (August 29, 1997).

(j) SFAS 106 Deferred Costs

The SFAS 106 costs were described and supported by Mr. O'Brien (DLC St. 4 at 13) and Mr. Clayton (DLC St. 2-R at 31). The OTS and OCA do not

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[39] This claim includes the expenses associated with the pilot program and customer education.

oppose their recovery. DLC Ex. DJC-10. PECO Energy approved recovery of a similar regulatory asset. PECO Energy, slip op. at 72-73.[40] DII and HSS, however, oppose recovery of them. As indicated by Mr. Clayton, however, it appears these parties misunderstand the nature of these expenses, which the Company was required by GAAP to record. DLC St. 2-R at 31. The costs should be approved.

(k) Warwick Mine Costs

The Warwick mine costs are described and supported by Mr. Clayton. DLC St. 2-R at 31-32. No party other than HSS opposes their recovery and it does so, again, applying the wrong standard. (The costs have been included in plant, not regulatory assets. DLC Ex. DJC-10.)

(l) Pilot Program/Customer Education Expense

These expenses were discussed under "Transition Costs" above.

(m) Compensated Absences

These costs were discussed under "Deferred Employee Costs" above.

(n) Injuries/Damages

These costs were discussed under "Deferred Employee Costs" above.

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[40] The portion of the SFAS 106 disapproved in that case related to costs associated with an early retirement program (PECO Energy, slip op. at 73), but no such issue is presented in this case.

(o) Other

N/A

3. Conclusion

The regulatory assets supported by Messrs O'Brien and Clayton should be approved in the amounts set forth in the tables attached to this brief.

F. Recovery of Stranded Costs

1. Introduction

The issues addressed in this section relate to (i) the level of stranded cost recovery, and (ii) the rate methodology for recovering such costs.

2. Proposals to Adjust the Level of Stranded Cost Recovery

(a) Mitigation

The only party that seriously questions Duquesne's mitigation efforts is HSS. HSS itself recognizes, however, that "Duquesne has taken steps towards mitigating costs" (HSS St. 1 at 65) and "has been making progress towards reducing its production and operation costs." Id. at 62. That is an understatement. As Mr. Clayton testified, by the year 2005 Duquesne's mitigation efforts will have achieved $1 billion in savings and $700 million in avoided rate increases. DLC St. 1 at 20; DLC St. 2 at 24-26; see generally DLC St. 2 at 3-26. Moreover, Duquesne is the only utility in the state to have auctioned a generating unit prior to the Act, using the proceeds to increase the depreciation of nuclear assets. DLC St. 2 at 10-12; DLC St.

1-R at 21. In stark contrast, HSS does not propose mitigation strategies. It simply proposes "adjustments" to lower rates, not operating costs.[41] The recommendations should be rejected as arbitrary and meritless.

(b) Sharing of Stranded Costs (OCA and DII)

The OCA, DII and the Environmentalists each recommend a "sharing" of stranded costs.[42] Mr. Schnitzer summarized the method and effect of each of the proposals as follows:

> 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 Industrials 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. DLC St. 3-R at 33-34.

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[41] For example, HSS proposes to reduce rates through "assumed" (not actual) reductions in capital expenditures and O&M expense. HSS St. 1 at 64. Another example of supposed "mitigation" is lowering Duquesne's approved ROE. Id. at 77-83.

[42] It should be noted that these "sharing" proposals must be addressed irrespective of whether Duquesne's auction proposal is accepted. OCA St. 1-S at 6.

There are four principal reasons why these proposals should be rejected. First, there is no support for them in the Act. The sole consideration set forth in the Act regarding the level of stranded cost recovery is mitigation. 66 Pa.C.S. § 2808(c)(4). Yet none of these parties has contended that Duquesne's mitigation efforts were inadequate (DLC St. 1-R at 18); consequently, there is no basis for any disallowance of its stranded costs. See PECO Energy, slip op. at 101 ("allowing PECO full recovery of its actual stranded costs").

Second, these proposals are not, as they purport to be, consistent with historic regulation in Pennsylvania. The OCA and DII contend that their proposals parallel past decisions regarding "economic excess capacity" (OCA St. 1 at 42; DII St. 1 at 16), but this is plainly not the case. As explained by Mr. Marshall:

> I am unaware of any case (and the parties do not refer to one) in which the Commission disallowed the recovery of embedded generation costs on the basis of a comparison of those costs to market price forecasts, which assumed that the capacity could be replaced by purchases in the spot market. No such assumption would have been appropriate, given that utilities have had an obligation to serve their loads on a long-term basis. That obligation has never been discharged through reliance solely on the spot market (or the "coordination" market as it has been called traditionally).

DLC St. 1-R at 20. Notably, neither the OCA nor DII rebutted Mr. Marshall on this point. OCA St. 1-S at 9; DII St. 1-S at 8-10.

Third, the proposals are arbitrary in that they bear no relation to the facts of this case. The OCA and DII proposals impose a pre-conceived return

disallowance without any regard to Duquesne's particular circumstances, its past mitigation efforts, or the effect of the disallowance on Duquesne. DLC St. 3-R at 37; DLC St. 1-R at 18. The Environmentalists' proposal is equally arbitrary, turning, as it does, on "an accident of history, the average vintage of Duquesne generation." DLC St. 3-R at 37. In sum, they are all "blunt instruments" that have a singular purpose: "to shift costs from customers to investors." Id.

Fourth, the proposals violate state and federal law, including Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989),[43] in two principal respects. First, the violate they "end results" test by failing to maintain the financial health of Duquesne. The financial impact of these proposals is profound (ranging from approximately $400 million to $760 million, DLC St. 3-R at 33-34) and "would severely damage the financial integrity of the Company." DLC St. 2-R at 45. Perhaps this is not surprising, given that none of these parties even bothered to evaluate the financial impact of its proposed disallowance on Duquesne. Second, they represent precisely the kind of "opportunistic switching" proscribed by the Court in Duquesne - i.e., the convenient modification of ratemaking standards at a

[43] See, e.g., Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n, 262 U.S. 679 (1923); Pennsylvania Pub. Util. Comm'n v. Pennsylvania Gas & Water Co., 492 Pa. 326, 424 A.2d 1213 (1980); City of Pittsburgh v. Weinberg, 544 Pa. 286, 676 A.2d 207 (1996); Pa. Const. Art. 1, § 10.

time when it benefits only customers. DLC St. 3-R at 38. As Mr. Schnitzer asserted, and no party rebutted, Duquesne has not been compensated for the effect of such a change in standards. DLC St. 3-R at 38-42. Indeed, the opportunistic nature of the switch could not be more apparent in this case, given the Commission's recent treatment of the Ft. Martin sale:

> As noted by many witnesses here, the sale price exceeded the book value of Duquesne's interest, but the proceeds were not used to increase the returns to shareholders beyond approved levels; rather, consistent with rate of return regulation, the gain was used to accelerate the amortization and depreciation of strandable assets. Thus, Duquesne's shareholders did not "share" the gains. It is therefore neither fair nor consistent for the OCA (and others) to contend that, for the remaining plants – where market values are below book values – it is "just and reasonable" for shareholders to bear an economic loss.

DLC St. 1-R at 20-21.[44] In sum, there is no basis in law or fact for the sharing proposals.

(c) Securitization (DII Proposal)

Mr. Kollen (DII) contends that "the Commission should insist that DLC utilize the securitization option." DII St. 3 at 35. The statute, however, does not permit forced securitization (66 Pa.C.S. § 2812) and the Commission did nothing of the kind in PECO Energy (slip op. at 101-102, 115). Moreover, in this case, such

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[44] The same point applies to the Commission's past treatment of the net revenues to be received from the proposed sale to GPU, which were to be passed through to ratepayers. DLC St. 1 at 26.

a requirement would be particularly inappropriate, given that: (i) Duquesne has the highest degree of debt leverage of any electric utility in the state, thereby already lowering Duquesne's cost of capital (DLC St. 2-R at 52); (ii) Duquesne cannot further reduce its common equity without violating the covenants in the Beaver Valley 2 sale/leaseback agreement (id. at 53)[45]; and (iii) Duquesne's debt cost is below the cost of securitized debt posited by Mr. Kollen. Compare DLC Ex. DJC-26 with DII St. 3-S at 27.

3. Methods of Stranded Cost Recovery

(a) Accelerated Amortization Under Section 2804(4)(v) (Duquesne's ROE Spillover Proposal)

Duquesne has proposed to set CTCs pursuant to Section 2804(4)(v); the OCA objects to this method because it does not produce immediate rate reductions. OCA St. 1 at 13. The OCA's argument cannot be accepted because Section 2804(4)(v) is written in proscriptive terms: it states that a utility "shall not" be required to reduce its rates upon the complaint of any party. 66 Pa.C.S. § 2804(4)(v).[46] Consequently, the only real issue is whether Duquesne's proposal for

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[45] Mr. Kollen naively assumes that these agreements can simply be "modif[ied]," apparently at no cost (DII St. 3-S at 28), but this is clearly not the case. DLC St. 2-R at 53.

[46] PECO did not propose to use Section 2804(4)(v) and hence it was not at issue in that case.

implementing Section 2804(4)(v) requires modification. On that issue, the only real dispute relates to the "ROE spillover" proposal.[47] The ROE spillover proposal is the mechanism by which any "excess earnings" are used to accelerate the amortization of stranded costs, as required by Section 2804(4)(v). DLC St. 2 at 40-44; DLC St. 2-R at 3-8. The proposal benefits consumers because it ensures that any excess earnings are "spilled over" to reduce stranded costs, but there is no guarantee that Duquesne will actually earn its required return. DLC St. 1 at 5.

There are two general criticisms of this proposal. The first is that the ROE spillover is set too high – i.e., that the ROE (11.5%) used to set earnings should be lower. OCA St. 1 at 12; OCA St. 1-S at 6. But this is simply a dispute over what is a fair return on common equity (a matter discussed in Section VI), not a criticism of Duquesne's plan to implement Section 2804(4)(v). The second is that the Company can "hide" excess earnings through devious accounting schemes, thereby circumventing the protective effect of the ROE spillover. OCA St. 1 at 12; OCA St. 1-S at 6; HSS St. 1 at 138. This is a cloud of dust. To ensure that Duquesne's earnings can be monitored, Duquesne has committed to file with the Commission the

[47] Notably, no party takes serious issue with Duquesne's commitment to amortize a minimum of $1.7 billion over the transition period (DLC St. 2 at 39-40; DLC Ex. DJC-6); this proposal provides ratepayers a guarantee that Duquesne will achieve the aggressive cost reduction and containment projections contained in its case-in-chief. DLC St. 1 at 5.

same reports it has filed historically to report its earnings and, in addition, to provide further information, if necessary, to "police" the process. Tr. 208-214, 359. Given these commitments, the suggestion that the Commission cannot, as it has for more than a half century, monitor the earnings of an electric utility is meritless. Tellingly, the OCA and HSS have failed to offer any modifications to strengthen these consumer protections; the reason is that the OCA and HSS dislike Section 2804(4)(v) itself, which does not guarantee their constituents immediate rate cuts. OCA St. 1 at 15-16; HSS St. 1 at 77-81. That, however, is a dispute with the General Assembly, not Duquesne.

(b) Immediate Rate Reductions (OCA Proposal)

The OCA proposal for immediate rate reductions conflicts with Section 2804(4)(v) and therefore cannot be approved.

(c) Rate Cap/CTC Extension

N/A

(d) Other Proposals

N/A

4. Other Arguments Regarding Recovery of Stranded Costs

The only other position that requires attention here is that of Mr. Hughes. Mr. Hughes makes one basic point: that Duquesne's nuclear units are not economic and, as a result, Duquesne should not be permitted to fully recover their

costs. DH St. 1. The result sought by Mr. Hughes, however, suffers from the same flaws as the "sharing" proposals discussed above: it bears no relation to Duquesne's mitigation efforts or opportunities and does not meet the standards set forth in Duquesne. In addition, as discussed by Messrs. Clayton and Duckworth, many of Mr. Hughes's factual claims are either in error or are attempts to rehash matters previously raised, and decided, in Duquesne's last rate case. DLC St. 2-R at 56-57; DLC St. 11-R at 1-10.

5. Conclusion

N/A

G. Conclusion

Consistent with the foregoing, the Judge should adopt a market-based valuation of Duquesne's generating assets (either an immediate auction or a final valuation in 2001-2003). If an immediate auction is ordered, the Judge should adopt the stranded cost recovery proposal described in Section IV.A. If a final valuation is ordered, the Judge should adopt Duquesne's stranded cost recovery proposal pursuant to Section 2804(4)(v).

V. THE COMPETITIVE TRANSITION CHARGE

A. Conceptual Disputes Regarding Calculation of CTC/CGC

1. Differences in Overall Approach (e.g., CTC or CGC as Residual; OCA Proposal)

The method for calculating the CTC is one of the most complex and misunderstood aspects of this case. While there are a multiplicity of proposals in this regard, they generally fall into two categories.

The first, proposed by Duquesne, is a "top down" approach that sets rates according to Section 2804(4)(v) of the Act. Under this approach, the CTC is calculated each year as a "residual" – i.e., it is that which remains after deducting (i) the distribution rate, (ii) the transmission and ancillary service rates, and (iii) the shopping credit (or CGC) from currently approved rates. See DLC St. 5 at 9-10. This proposal has two other important features as well. First, the shopping credit adjusts each year to track changes in market prices (id. at 56); consequently, because it is a residual, the CTC adjusts each year in inverse proportion thereto. Second, as required by Section 2804(4)(v), excess earnings, if any, will be used to accelerate stranded cost amortization and shorten the CTC collection period. DLC St. 2 at 42-43.

The second general approach, proposed by the OCA (and applied in modified form in PECO Energy), is a "bottoms up" methodology. This methodology

differs from the one described above in that (i) the CTC is not calculated with reference to current rates (i.e., after subtracting T&D and CGC rates); (ii) there is no accelerated amortization of stranded costs; and (iii) the CTC does not vary each year to reflect actual changes in market prices. OCA St. 4 at 14-15; OCA Ex. LS-4; PECO Energy, slip op. at 41-42. Rather, the CTC is a fixed schedule of payments[48] designed to recover a fixed amount of stranded costs over a set period of time. OCA Ex. LS-4; PECO Energy, slip op. at 41-42.

These two proposals are marked by two key differences that generate the intense disputes that have arisen in this case. The first is that the OCA methodology will tend to produce immediate rate reductions[49] (given certain stranded cost assumptions) and lengthen the CTC collection period, while Duquesne's methodology will maintain current rate levels while tending to shorten the CTC collection period (again, given certain assumptions). The second difference is that under the OCA methodology, there is no guarantee that the shopping credit will reflect current market prices, while a basic premise of Duquesne's approach is that the shopping

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[48] Under the OCA proposal, the fixed CTC schedule declines each year (OCA Ex. LS-4), while under PECO Energy the CTC is "levelized." PECO Energy, slip op. at 41.

[49] Under the OCA proposal, all customers will receive such rate reductions (whether or not they switch suppliers) (OCA St. 4 at 15), while under the PECO Energy Order only customers that "shop" for power receive rate reductions. PECO Energy, slip op. at 43.

credit must accurately reflect market prices to ensure that customers face the right price signals. DLC St. 5 at 56.

These debates, while vigorous, are academic because under Section 2804(4)(v) Duquesne has the statutory right to continue charging current rates and use any excess earnings to accelerate the amortization of stranded costs. To be sure, there are other, subsidiary disputes that require careful attention (e.g., the appropriate methodology for determining the shopping credit), but this threshold question has been decided, in Duquesne's favor, by the Act.

2. Other Conceptual Disputes

N/A

(a) CGC Calculation: Annual Adjustments v. Fixed Schedule

The Duquesne and OCA methods differ in that Duquesne's shopping credit will adjust each year (per the RFP results for that year), while the OCA sets a fixed shopping credit in advance for each year of the transition period. The differences in approach are vitally important because of the rate cap, as explained by Mr. Marshall:

> The OCA and DII propose to set CGCs at a fixed level throughout the transition period, using their computer forecasts of market prices. They readily concede that, under this approach, if market prices rise to levels above the fixed CGC, customers will return to Duquesne and take service at the rate cap. "Taking service at the rate cap" means, for purposes here, purchasing unbundled generation from Duquesne at

a price equal to the CGC. When market prices rise above that level, purchasing from Duquesne is clearly preferable to paying a marketer the actual (higher) market price. In such a scenario, the customer is protected and Duquesne is protected, given that the CGC was set on the basis of a market price prediction that, in retrospect, was too low. However, the suppliers are harmed (they contend) because customers will have an artificial incentive to return to service from Duquesne.

Now consider the opposite scenario -- in which market prices fall below that projected in the CGC. In this situation, customers are again protected because they are not required to purchase power from Duquesne at the CGC. Consequently, one would expect them to purchase power in the open market at lower rates. Suppliers too will benefit under this scenario, given that customers are less likely to continue purchasing from Duquesne under the rate cap. The loser in this scenario, of course, is Duquesne. Duquesne will fail to fully recover its stranded costs because the fixed CGC, in retrospect, was set too high and, hence, the CTC was set too low.

As the foregoing illustrates, customers have a natural incentive to "lock in" the CGC because they gain "certainty" without any adverse economic effects associated with the resulting loss of accuracy in forecasting the CGC. The suppliers, on the other hand, have the incentive to adjust the CGC on an annual basis to reflect actual market prices. Suppliers also, however, have an incentive to fix the CGC in advance, provided that it is set so far above market prices that they bear no material risk of market prices exceeding the CGC in any year. The latter incentive is illustrated by Mr. Russell's proposal to set the CGC on the basis of the cost of constructing a new generating unit, even though he concedes that ECAR has excess capacity....

The only fair resolution is to set the CGC at the market price and that is precisely the purpose of Duquesne's RFP proposal. I recognize that many parties have criticized the RFP as producing prices that are "too low". While this is not the point -- the goal is to establish a method that measures actual market prices -- I note that the market prices produced by the eight-year RFP are nearly identical to those forecast by the OCA, with the sole exception of an artificial "bump" in market prices that OCA predicts will occur in 2003 due to

> the addition of new capacity. Whether or not this spike in prices actually occurs is, of course, a matter of speculation, but, from the results of the eight-year RFP, the market is predicting that it will not occur. More to the point, however, none of the parties (with the exception of Mr. Boonin) offers any concrete alternative for calculating the true market price of power in the Duquesne region. In the absence of any such alternative, the Commission should accept Duquesne's proposal.

DLC St. 1-R at 21-23 (emphasis in original). For the reasons stated by Mr. Marshall (and explained further by Messrs. Schnitzer and Lahtinen, DLC St. 3 at 40-45; DLC St. 5 at 56), the Judge should adopt Duquesne's proposal to adjust the shopping credit each year to reflect actual market prices.[50] The methodology for doing so (the annual RFP) is addressed in more detail in Subsection B.1 below.

(b) Determination of Class Responsibility for Stranded Costs

This section addresses a dispute between the OCA and DII.

(c) Levelized CTC v. Other Methods

N/A

[50] Duquesne notes that, to address a potential preference by some customers for a fixed CTC, Duquesne offered an option in its pilot program to fix the CTC in advance provided that electing customers waived their right to return at capped rates, but the proposal was uniformly opposed by the parties and was not accepted. DLC St. 1-R at 15.

(d) Duquesne's Rate Redesign Proposal

Duquesne has proposed to redesign its rates in a manner that "will allow customers to make more efficient consumption decisions, while also providing additional revenues that can be applied to mitigate stranded costs." DLC St. 1 at 11. Duquesne's rate redesign proposal "mov[es] a significant portion of generation-related costs into a fixed customer charge, which results in a lower variable (per kWh) charge than exists today." Id. This, in turn, produces a reduction in marginal rates of 25% on average and a 50% reduction in rates for residential customers, thereby moving rates much closer to the marginal cost of production. DLC St. 5 at 34. These more efficient rates will encourage increased usage, which will increase stranded cost mitigation. DLC St. 1 at 11; DLC St. 5 at 33.[51] While the dollar impact of this mitigation is difficult to predict, it may equal or exceed $15 annually. DLC St. 5 at 34. The proposal also has no downside: there is no cost-shifting between classes and "no customer will pay more than he does today" for the same level of usage. Id. at 32.

Despite the clear efficiency of this proposal, and its significant mitigation benefits, a range of parties oppose it. These parties essentially raise three

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[51] Mr. Lahtinen explained the derivation and effect of the redesigned rates, and the underlying assumptions regarding demand elasticity, in excruciating detail in direct testimony. DLC St. 5 at 32-47.

arguments. The first is that it "shifts risk" from shareholders to ratepayers by moving a portion of stranded costs into a fixed customer charge. DII St. 1 at 51-52; OCA St. 2 at 8. This is incorrect and, in any event, is no longer even an issue. First, the assertion would be true only if Duquesne's customer demand fluctuated widely each year, thereby posing significant risks if fixed costs were recovered solely through a variable charge; however, no party alleges such facts and they do not exist. Duquesne's customer demand is relatively flat, increasing slowly each year. DLC Ex. DJC-3 at 2. As Dr. Makholm testified, "it is my opinion that the fixed customer charge will have little or no effect on Duquesne's risk." DLC St. 12 at 37. Second, and in any event, in response to the concerns of the intervenors, Duquesne has now made the rate redesign optional for customers. DLC St. 5-R at 45. This means that, for customers that expect their usage to drop, they can choose not to use the rate redesign;[52] and for customers that expect their usage to increase, they can select rate redesign and reduce their marginal rates significantly.

The second criticism is that the proposal "shifts costs" between customers and/or rate classes, which is a meritless contention advanced only by

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[52] Despite this offer of optional service, the OCA's Ms. Smith in surrebuttal continued to oppose the rate redesign proposal; however, given that she did not mention this offer, and her continued concern regarding customers that reduce their usage and hence pay more (on a total $ basis) with a fixed customer charge (OCA St. 4-S at 8), it is not clear she was aware of the offer.

MAPSA's Mr. Russell. As other witnesses concede (albeit grudgingly),[53] and as Mr. Lahtinen demonstrated in detail, cost shifting is simply not possible under Duquesne's proposal:

> the Company's approach to unbundling insures that no customer pays more in total (for the sum of his unbundled rate components assuming power is purchased at the CGC rate) than he would have paid under current bundled tariffs at the test or base year level of sales. This is a basic arithmetic identity of the top down approach in general and the Duquesne proposal here. [See DLC Ex. JAL-4.] Moreover, unlike the top down approaches proposed elsewhere (California and New York) which maintain revenue neutrality between bundled and unbundled rates on a class specific basis, Duquesne's approach maintains revenue neutrality on a customer specific basis. Since there is no shifting of revenues at the base year level of sales there can be no cost shifting. *This test of cost shifting is a traditional measure used* by regulatory jurisdictions since time immemorial to compare the cost shifting implications of alternative rate designs. Rate design alternatives are always assessed on the basis of **test year sales** to insure that each alternative recovers the same overall level of revenues, and to see whether there is cost shifting across classes and finally to determine individual customer impacts within a rate class.

DLC St. 5-R at 41 (emphasis in original). Mr. Russell's unwillingness to acknowledge this obvious point (MAPSA St. 1-S at 6) is "intellectually indefensible." DLC St. 5-Rej. at 6.

The third claim is the OCA contention that the redesigned rates may be too low – i.e., that they may not even "equal...the full marginal cost" of providing

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[53] DII St. 1 at 52 ("specific costs have not been explicitly shifted under the Company's proposal").

distribution service. OCA St. 4 at 8. As Mr. Lahtinen explained, however, this is a baffling assertion (DLC St. 5-R at 39) given that OCA has claimed that Duquesne's rates "must" be reduced (OCA St. 1 at 15) and has proposed reducing them by 18%. OCA Ex. LS-4. Tellingly, the OCA offers no evidence in support of this assertion (OCA St. 4 at 8) and, as Mr. Lahtinen explained, it is meritless. DLC St. 5-R at 44-45.

In sum, Duquesne's rate redesign proposal should be accepted, including the modification that makes redesign optional for customers; with that modification, there is no legitimate reason for not approving the proposal.

(e) Other Conceptual Disputes

N/A

3. Conclusion

See subsection D below.

B. Other Disputes Regarding Specific Proposals

1. Duquesne

Duquesne proposed to adjust the shopping credit to reflect the results of an annual RFP for the sale of firm power. DLC St. 5 at 56. The point of the RFP was to objectively establish the prevailing market price of power during the transition period and to make available to customers and suppliers a local source of power. DLC St. 3 at 40-45. MAPSA and HSS, however, vehemently criticize the RFP

proposal. Three points in response are sufficient. First, while Mr. Lahtinen has rebutted each criticism (DLC St. 5-R at 6-26; DLC Ex. JAL-14; DLC St. 5-Rej.), the telling point is that these parties fail to offer any realistic alternative to the RFP. DLC St. 5-R at 12. While their spirited attacks on the RFP may be entertaining to them, this strategy is utterly unproductive in advancing the important objective of establishing a market-based shopping credit – an objective with which neither party quarrels.

Second, to simplify the disputed issues in *this* case, and to demonstrate its good faith, Duquesne offered to modify the RFP proposal as follows:

> [S]everal parties have criticized the contract terms for the proposed power sale. Duquesne's response is two-fold. First, Duquesne is willing to submit its proposed power sale auction (both the proposed contracts and the solicitation procedures) to the Commission for prior approval. Consequently, the Commission will have the opportunity to satisfy itself that the terms of the solicitation are adequate to set a market-based CGC. Second, Duquesne will cease using the RFP process if an index for market clearing prices is established in the Duquesne area that is representative of the market prices for Duquesne-supplied generation. While such an index does not exist today, it is possible that during the transition period one may develop. Should such an index be established, the need for an RFP would no longer exist and Duquesne would petition the Commission to substitute index prices for the prices resulting from Duquesne's RFP.

DLC St. 1-R at 3. This offer should have eliminated the disputes with HSS and MAPSA regarding the procedure for setting a shopping credit, but these parties remain undeterred. HSS fails to acknowledge any benefits of this offer, simply

asserting that it "recogniz[es]" the RFP is "inherently flawed." HSS St. 1-R at 40. This is hardly fair, as Mr. Marshall's testimony suggests nothing of the kind. For its part, MAPSA contends that the offer is "unclear" and suggests that Duquesne may have hidden intentions. MAPSA St. 1-SR at 9. Again, this simply underscores the fact that MAPSA has no interest in a constructive debate regarding a market-based shopping credit.

Finally, the heart of the MAPSA and HSS claims is that the terms of the RFP "artificially" depressed the bid prices received by Duquesne. MAPSA St. 1 at 25; HSS St. 1 at 26. The obvious implication is that market prices are above the RFP bids and Duquesne could have received better prices if it had designed a better RFP. The proof, however, is in the evidence and all the data in the record on actual market transactions (not forecast prices) matches the winning bid prices produced by the RFP:

Record Citation	**Source of Data**	**Price (¢/kWh)**
DLC St. 5 at 73-74	FERC Form 714	1.79
DLC St. 5 at 76	Power Markets Week	1.82
DLC St. 7 at 4	Prior Duquesne Sales	1.75
DLC St. 7 at 10	Duquesne 1-Year RFP	1.82

It is thus wrong to suggest that, if the RFP's supposed "design flaws" (HSS St. 1 at 27) were rectified, higher bids would have been forthcoming. The foregoing data show that there is very little uncertainty regarding the market price for power in

ECAR today. The problem is that MAPSA and HSS don't like these low prices, which are apparently unhelpful to their pursuit of an artificially low CTC for Duquesne.

2. OCA

In addition to the conceptual disputes discussed previously as to the OCA and DII proposals, there remain significant disputes regarding the implementation of their CTC design proposals, particularly with respect to deferred taxes (DLC St. 2-R at 44), in a manner that would allow Duquesne to recover (after tax) the amount of stranded costs determined to be just and reasonable. These complex issues are better addressed in the compliance phase of the case if their proposals are adopted.

3. DII

N/A

4. Other Proposals

N/A

C. Other Issues Addressed in PECO Order

In PECO Energy, the Commission accepted evidence that, with respect the CTC proposed by PECO, a long-term debt rate represented the appropriate cost of capital. PECO Energy, slip op. 107. While Duquesne does not agree with that finding, it is not pertinent here. Duquesne has not proposed a "fixed" CTC that

is "trued up" each year for changes in sales levels, as was proposed in PECO Energy. Rather, Duquesne has proposed an ROE spillover and a commitment to amortize a minimum of $1.7 billion in stranded costs over the transition period. According to testimony not directly disputed by any witness,[54] this proposed "places risk on Duquesne's shareholders that is greater than it would be under traditional regulation." DLC St. 12 at 37 (emphasis added). In particular, the proposal places asymmetric risk on Duquesne that simply does not exist today:

> Under Duquesne's proposal, shareholders will bear the risk that cost containment measures are not sufficient to generate the savings necessary to satisfy this commitment while maintaining earnings. If, to the contrary, revenues exceed expectations or additional cost savings are available, Duquesne has established an ROE "spillover" mechanism that will ensure that the related revenues are used to mitigate stranded costs, rather than to permit shareholders to earn higher than a fair return.

DLC St. 1 at 5 (emphasis in original). Consequently, the findings in PECO Energy do not apply to this case.

D. Conclusion

Duquesne's CTC design proposal, as described and supported by Mr. Lahtinen (DLC St. 5), should be approved. If the immediate auction is accepted,

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[54] Each witness that criticized Duquesne's stranded cost recovery proposal carefully avoided contending that the proposal would, taken as a whole, including the $1.7 billion minimum amortization commitment, place less risk on Duquesne's shareholders than exists today.

Duquesne is willing to accept a CTC design that generally is consistent with the method used in PECO Energy, as discussed in more detail in Section IV.A.2.

VI. RATE OF RETURN/DISCOUNT RATE

Duquesne's witness, Dr. Makholm, performed a fully supported Discounted Cash Flow ("DCF") analysis in order to calculate the Company's return on equity ("ROE"). See DLC St. 12 and DLC St. 12-R. Based on this DCF analysis, Dr. Makholm concluded that an 11.65% ROE for Duquesne was fair and reasonable. DLC St. 12 at 3. To be conservative, Duquesne is requesting an 11.5% ROE. DLC St. 2 at 47.

Of the interveners, only OTS witness Mr. Van Jeschke presented a rebuttal, in any detail, to Dr. Makholm's testimony. OTS St. 1.[55] Mr. Van Jeschke's testimony raises three major issues: (i) composition of the proxy group used for the DCF analysis; (ii) use of an adjustment to correct for the effect of the "ex-dividend date," and (iii) inclusion of a factor to account for flotation costs.

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[55] OCA witness Mr. Kahal arbitrarily picked an ROE of 10% because this number was used in the "PECO QRO" case. OCA St. 1 at 26. But returns on equity are not "fungible"; they are company specific, as any responsible analyst would acknowledge. DLC St. 12 at 12; DLC St. 12-R at 15-16. Mr. Kahal's unsupported analysis should be rejected. DLC St. 12-R at 15-16. Mr. Muehl, on behalf of David Hughes, presented testimony concerning Duquesne's level of return (DH St. 2); however, as explained by Dr. Makholm (DLC St. 12-R at 17-19), Mr. Muehl's understanding of the utility regulatory process is so flawed that his testimony must be rejected.

The first issue is the composition of the proxy group. The two major disagreements on selection criteria centered on whether the group should include utilities with nuclear generation and whether utilities involved in a merger should be included. Dr. Makholm did not include utilities that met either of these criteria, while Mr. Van Jeschke did. DLC St. 12-R at 3-6; OTS St. 1 at 15-20, 41-42. Dr. Makholm's selection criteria should be accepted. His analysis is more conservative and more reliable because he excluded utilities that met these criteria. DLC St. 12-R at 4-6. Utilities that own nuclear generation have higher risk (and ROEs) than those that do not. Id. Furthermore, the stock price of utilities involved in mergers can swing wildly, thus producing unreliable DCF results. Id.

The two remaining disputes concern adjustments to the DCF calculations themselves. The first adjustment made by Dr. Makholm was to adjust for the ex-dividend date. As Dr. Makholm explains, the DCF model contains certain assumptions regarding the ex-dividend date, and if a correction is not made the resulting DCF calculation will result in an ROE that is too low. DLC St. 12 at 21-22; OTS St. 1 at 43-44; DLC St. 12-R at 7-8. Mr. Van Jeschke does not deny that this effect exists; however, he testifies that there is no "conclusive" evidence that the stock price change can be attributed solely to this effect, and further, that the effect should average out over time. OTS St. 1 at 43-44. Dr. Makholm, however, provides ample evidence of the existence of, and need to correct for, this effect and demon-

strates that it does not average out over time. DLC St. 12 at 21-22; DLC St. 12-R at 7-8. Thus, Dr. Makholm's adjustment for the ex-dividend date should be accepted.

The second adjustment made by Dr. Makholm is to account for flotation costs. DLC St. 12 at 26-29. Without this adjustment, the net proceeds from the issuance of common equity will be less than the sales price of that issuance. These costs typically are allowed to be recovered on debt and preferred equity issuances. Id. Dr. Makholm recognized that the Commission, however, typically denies recovery of these costs, holding that flotation costs are already included in the market price of the stock that is used in the DCF calculation (id. at 28; see OTS St. 1 at 45-46), but Dr. Makholm shows that there is no evidentiary support for this in the financial literature. DLC St. 12-R at 11-13. Moreover, it is inconsistent to allow the recovery of these costs on debt and preferred equity issuances and to deny their recovery on common equity issuances. DLC St. 12 at 28. Accordingly, Duquesne has made this adjustment (of 5%), and it should be accepted by the Commission in this proceeding.[56]

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[56] Dr. Makholm also performed a simple reasonableness test of each witnesses' recommended ROE. He compared the recommendations against the range of electric utilities ROE's authorized by regulatory commission throughout the country between April 1995 and March 1997. From this comparison, it is apparent that Dr. Makholm's recommended ROE is in the middle of the range while those of Mr. Van Jeschke and Mr. Kahal are at the extreme low end, or even outside of, the range. DLC St. 12-R at 14-16.

In sum, Dr. Makholm's recommended ROE should be adopted as the most reasonable ROE presented in this proceeding.

VII. SPECIAL CUSTOMER CLASSES

A. Rule 4 Contracts

Rule 4 Contracts are executed "as a mitigation strategy to attract or retain incremental load that Duquesne would have otherwise lost to a competitive alternative." DLC St. 6-R at 4; see also Tr. 1029-30. Two issues have arisen regarding these contracts. First, DII contends that Rule 4 contracts should be unbundled so that customers can gain access to the competitive market. DII St. 1 at 54. This contention should be rejected. Rule 4 contracts were entered into between sophisticated parties and were tailored to the specific circumstances of each customer. DLC St. 6-R at 4. They have provided benefits to these customers and to the region as a whole. Id. at 4-6. As in PECO Energy, these contracts should "remain in effect according to their terms." PECO Energy, slip op. at 120.[57]

The second contention is OCA's argument that the revenue effect of Rule 4 "discounts" class should be imputed, for CTC calculation purposes, to the class receiving the discounts. OCA St. 4 at 8-10. This proposal is based on a

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[57] Of course, if the contracts themselves permit unbundling, Duquesne will, at the request of the customer, unbundle them consistent with the methodology for all other customers, consistent with PECO Energy, slip op. at 120.

misunderstanding of the nature of a Rule 4 contract. DLC St. 6-R at 6. Rule 4 "discounts" do not represent lost revenues; they represent discounts applicable to incremental load and, hence, represent additional revenues that would not otherwise have been earned. Id. The factual basis for the OCA proposal – that the discounts create a loss of revenue – is therefore mistaken. If, however, the OCA proposal, which forces Duquesne's shareholders to bear an economic loss, is adopted, Duquesne reserves the right to cease economic development activity under Rule 4.

B. Riders 8 and 20

Duquesne offers the following three economic development tariff riders: (i) Rider 8, which offers discounts for incremental consumption by existing industrial customers; (ii) Rider 9, which offers discounts for new load from large new customers; and (iii) Rider 20, which offers discounts for both incremental consumption by existing commercial customers and new load from new commercial customers. DLC St. 6 at 16. The issue presented here is whether Duquesne, as it has proposed, should eliminate the discounts for incremental load from existing customers (Rider 8 and part of Rider 20), but not discounts for new load from new customers. DLC St. 6 at 18; DLC St. 6-R at 3. DII contests this proposal (DII St. 1 at 58-59), but it is clearly appropriate. Duquesne has made this proposal because the riders regarding existing customers are no longer necessary; Duquesne's proposed rate redesign does the same thing: it provides a discount on incremental usage by

existing customers. See Section V.A.2(d); see also DLC St. 6-R at 3-4. Accordingly, if the riders were retained, these customers would simply receive a "discount on a discount," which is not economically efficient or consistent with stranded cost mitigation. DLC St. 6-R at 3-4.

C. Self-Generation

The Environmentalists recommend that Duquesne promote the use of self-generation facilities, such as solar and fuel cells, through a "net metering" arrangement. Environ. St. 1 at 7-8. This proposal conflicts with the Act because it would permit customers who install generation to avoid paying an equitable portion of stranded costs. DLC St. 5 at 79-80. Section 2808(a) of the Act provides that if a customer installs on-site generation "which significantly reduces the customer's purchases of electricity through the transmission and distribution network, the customer's fully allocated share of transition or stranded costs shall be recovered from the customer through the competitive transition charge." 66 Pa.C.S. § 2808(a); see also PECO Energy, slip op. at 124. The proposal should be rejected.

D. Other Tariff-Related Issues

N/A

VIII. COMPETITIVE SAFEGUARDS

A. Code of Conduct

Duquesne proposed a Code of Conduct to ensure an adequate separation of the regulated and unregulated portions of Duquesne's business. DLC Ex. FH-2. Many parties, however, paid no attention to it, such as Enron. Enron criticizes a different code of conduct – the code adopted in Duquesne's pilot proceeding – not the one proposed by Duquesne in this case. Compare Enron St. 1.0 at 7-8 with DLC Ex. FH-2. Whatever the level of attention (or inattention) to this matter, this is an issue that should be decided on a generic basis for all EDCs and suppliers in the Commonwealth. DLC St. 6-R at 28.

B. Pro Forma Tariffs

This section relates to another proposal by Enron that should be addressed by the Commission on a generic basis, not in this case. The proposal is for a new "Pro Forma Electric Generation Supplier Tariff." Enron Ex. LRC-2. As its title indicates, the Tariff bears no relation to the particular circumstances of Duquesne and thus, not surprisingly, many of Mr. Cole's assertions regarding the "inadequacies" of Duquesne's direct access proposal ignore the specifics of that proposal. In any event, the issue is generic and need not be resolved here. DLC St. 7-R at 1-4.

IX. DUTY TO SERVE

A. Service to Returning Customers

Duquesne has proposed that customers returning to "rate cap" service must remain with Duquesne for 12 months thereafter to address certain "gaming" opportunities. DLC St. 5 at 69-70. The proposal will protect Duquesne against customers leaving the system during low cost periods and returning to rate cap service during high cost periods (e.g., the summer peak period). Id. OCA objects to this requirement as "discouraging participation in the competitive market" (OCA St. 5 at 52), yet offers no real alternative. OCA suggests that Duquesne could charge an unspecified "fee" whenever a customer switches "more than twice in any twelve month period." Id. This proposal has several problems. First, it has an arbitrary limitation on the number of switches; it takes only one switch per year to avoid purchasing from the market during the peak (i.e., expensive) summer months. Second, the OCA fails to specify a fee that could adequately compensate Duquesne for the resulting harm (and we question whether any "set" fee would be workable,

given the significant price fluctuations that occur during these months).[58] Its proposal should therefore be rejected.

B. Provider of Last Resort

The Environmentalists have proposed the same "Better Choice Plan" that was rejected in PECO Energy, slip op. at 135. The Judge should decline to adopt it here.

C. Electric Transmission and Distribution Service

1. Unbundling Other Customer Services

(a) Introduction

The issues addressed in this section (the unbundling of "revenue cycle services") are principally matters of generic policy that the Commission should decide on a fair and consistent basis for all EDCs and suppliers in the Commonwealth in a generic proceeding. DLC St. 8 at 3; DLC St. 8-R at 3-4. This also is consistent with PECO Energy, where the Commission held it "not appropriate or necessary" to require PECO to unbundle revenue cycle services in that proceeding.

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[58] OCA also suggests that Duquesne's rate redesign proposal, which the OCA opposes (see Section IV.A.2(d)), adequately addresses this concern. OCA St. 5 at 52. This characterization is untrue and elevates "bootstrapping" to a new level – claiming that one proposal opposed by the OCA supports the rejection of another proposal opposed by the OCA. The claim, if taken seriously, simply reflects the OCA's failure to recognize that the rate cap imposes real risks on Duquesne that cannot be so cavalierly disregarded. DLC St. 1-R at 21-23; Section IV.A.2(a).

PECO Energy, slip op. at 138. While there is thus no requirement to address these matters in detail (Fifth Prehearing Order, page 3), Duquesne will discuss each briefly.

(b) Resolution in Generic Proceedings v. Resolution in this Case

As indicated, the unbundling of revenue cycle services is a generic issue that should be addressed in a rulemaking proceeding. The Commission has already initiated rulemakings to address several of these issues through a collaborative process. DLC St. 8-R at 3 (citing Guidelines for Maintaining Customer Services, Docket No. M-00960890F0011, 1997 PaPUC LEXIS 42 (July 11, 1992) (customer billing)("Customer Services Guidelines); Advanced Meter Deployment for Electricity, Docket No. L-00970120, 28 Pa. Bull. No. 5 (Jan. 31, 1998) (customer metering) ("Proposed Rulemaking" or "Advanced Metering Guidelines")).

(c) Interim Rules Applicable to Duquesne

N/A

(d) Specific Services

(i) Customer Billing

The main issue here is whether the PUC should allow customers to receive a single bill from their chosen generation supplier that includes billing of EDC charges. The Commission should not require this. DLC St. 8-R at 21-22. The

PUC's rulemaking governing interaction between customers, suppliers and EDCs also supports not implementing a supplier billing option at this time.[59] Furthermore, in PECO Energy, while the Commission recognized that there may be potential benefits to the third billing option, it nevertheless ordered PECO to provide all billing services, including generation services billing, unless a customer were to choose to receive a separate bill directly from its supplier. PECO Energy, slip op. at 139.

(ii) Metering

The main issue here is whether to unbundle metering services, which several intervenors urge the Commission to do. OCA St. 5 at 41-42; MAPSA St. 1 at 42-46; Enron St. 4 at 5-6; Enron St. 1 at 5; Enron St. 3 at 22; NEV St. 1 at 21; NEV St. 2 at 4. These proposals must fail under PECO Energy. PECO Energy, slip op. at 140 ("As indicated in our rulemaking at Docket No. L-00970120, we do not believe it is necessary to unbundle metering as a competitive service at this time").

(e) Conclusion

N/A

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[59] Customer Service Guidelines, 1997 Pa. PUC LEXIS 42 at 26 ("[W]e believe an approach that initially focuses on implementation of the two billing option explicitly set forth at Sec. 2807(c) is necessary to maintain customer service functions at the current levels of quality as required by Section 2807(d).")

2. Agency

The issue is whether a supplier can act as an agent for the customer and provide a "total electric package," including billing and collection. Enron St. 3 at 13. The proposal should be rejected because: (i) the Customer Choice Act does not authorize this type of agency arrangement and the PUC's Customer Services Guidelines would appear to prohibit it (1997 Pa. PUC LEXIS 42 at *1); (ii) if the supplier were to act as agent, it would have to provide metering and disconnection services (DLC 8-R at 22), but under the guidelines only the EDC, Duquesne, can provide metering services for customers (id. at *1, *51); and (iii) agency is inextricably linked with the single supplier bill option (Enron St. 3 at 13), but the PUC has not yet endorsed the supplier bill option. Customer Services Guidelines, 1997 Pa. PUC LEXIS 42 at *26; PECO Energy, slip op. at 139.

3. Other Issues (e.g., CARS system)

Prior to the Act, Duquesne entered into a 15-year contract requiring Itron, Inc. to install, operate and maintain an automated metering service, Customer Advanced Reliability System (or "CARS"). DLC St. 8-R at 10. Upon a review of the arrangements, the Commission's Director, Bureau of Transportation and Safety, stated that "[w]e are extremely pleased that your company has decided to install an automatic, meter-reading system." DLC Ex. FRA-5. At present, Itron has installed a

substantial portion of the system and it should be fully operational by December 31, 1998. DLC St. 8-R at 12.

The Intervenors have three main objections to CARS: (i) CARS will not satisfy the Commission's Advanced Metering Guidelines[60] (OCA St. 5 at 40); (ii) CARS may be "anti-competitive" and hinder retail competition (Enron St. 3.1 at 4, 6-7; OCA St. 5 at 40-41); and (iii) the Commission stop Duquesne from installing a "gold-plated" system, or alternatively, make Duquesne shareholders at risk for this investment. Enron St. 3.1 at 4-5, 6; OCA St. 5 at 41. Each is addressed below.

First, the PUC has not yet finalized advanced metering standards. Tr. 855; DLC St. 8-R at 17-18. Once those standards are set, "Duquesne and Itron will work with the Metering Committee to qualify CARS, ensuring that distribution system benefits, etc. are accessible to competitive suppliers." DLC St. 8-R at 17-18. Second, CARS is pro customer choice and will promote, not hinder, competition. DLC St. 8-R at 11.[61] CARS will support a more reliable and accurate supplier

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[60] Advanced Meter Deployment for Electricity, Docket No. L-00970120, 28 Pa. Bull., No. 5 (Jan. 31, 1997) ("Advanced Metering Guidelines" or "Proposed Rulemaking").

[61] The OCA incorrectly asserts that CARS gives Duquesne a marketing advantage since the reliability benefits are not shared by suppliers. OCA St. 5 at 40-41. Duquesne will provide retail suppliers equal access to CARS' service offerings. Moreover, the reliability benefits relate to distribution service, not generation. DLC St. 8-R at 16.

settlement process than programs based on estimated load profiles. Id. at 11, 16. CARS will enable retail suppliers in Duquesne's service area to offer new value-added services to their customers, such as time-of-use pricing. Id.[62] Moreover, CARS does not preclude the unbundling of billing or other services in the future. Id. Third, CARS is not a "gold plated" system. CARS streamlines the use of distribution system assets, lowering overall service costs. Id.[63] These benefits will accrue to customers that choose alternative suppliers as well as customers that do not. DLC St. 8-R at 11.

D. Consumer Protection and Service Issues

1. Termination

Duquesne will address this issue, as necessary, in reply brief.

2. Switching Fees

Duquesne will address this issue, as necessary, in reply brief.

E. Partial Payments

Duquesne will address this issue, as necessary, in reply brief.

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[62] Duquesne will make optional services available to competitive suppliers and/or customers in a non-discriminatory manner, consistent with open access codes of conduct. These optional services will be cost-based and Duquesne will submit tariffs for these services for PUC approval. DLC St. 8-R at 11.

[63] Meter reading costs have declined since the partial implementation of CARS. DLC St. 8-R at 15.

X. UNIVERSAL SERVICE AND ENERGY CONSERVATION

A. Introduction

N/A

B. Overall Funding and Rate Issues

1. Eligibility and Funding Levels

The intervenors advocate a broader definition of need than Duquesne, thus expanding the pool of persons eligible for assistance. See, e.g., OCA St. 6 at 17-18; Pitts. St. 2 at 7-8, 12, 14-15. They base their estimates of the number of eligible persons solely upon income criteria. However, neither the Act nor the Commission's Guidelines on Universal Service and Energy Conservation Guidelines (the "Guidelines") require that all customers with a specific level of income be eligible for all services, or that additional eligibility criteria, as proposed by Duquesne, are improper. Specifically, Section 2804 of the Act only requires that such activities be "appropriately funded and available" and operated in a cost-effective manner. Moreover, the Commission's Guidelines (at 31-34) specifically include "other non-income criteria" in the definition of eligibility. DLC St. 14-R at 9. Furthermore, Duquesne's use of additional eligibility criteria is consistent with PECO Energy (slip op. at 143-144), which approved PECO's use of additional eligibility criteria.

2. Cost Allocation and Rate Design

Duquesne has proposed to allocate and collect the universal service charge by rate class on a cents per kWh basis based on allocated distribution costs for each rate class. DLC St. 14-R at 24-25. Mr. Colton agrees with this approach and Ms. Brockway agrees that it is not inconsistent with the Commission's final order (though she has her own preferred method). Pitts. St. 2 at 13-14; OCA St. 6 at 49. Only Mr. Yarolin of OTS presents a contrary view and suggests that the charge be collected on a dollars per customer basis. OTS St. 3 at 5-6. This proposal is patently unfair since it results in a small residential customer and a major corporation making the same monthly payment to support universal service. Thus, Mr. Yarolin's suggestion should be rejected and Duquesne's proposal accepted. DLC St. 14-R at 24-25. Also, Mr. Yarolin's suggestion that this charge be unbundled from the Distribution Charge should be rejected. OTS St. 3 at 6-7. It is contrary to PECO Energy (slip op. at 144).

C. Specific Programs

1. CAP Program

OCA witness Brockway and City of Pittsburgh witness Mr. Colton make numerous recommendations as to particular items that should be included in the program. OCA St. 6 at 27-38; Pitts. St. 2 at 8-14. Mr. Flynn addresses each of their recommendations in detail in his rebuttal testimony. DLC St. 14-R at 11-21.

Mr. Flynn notes that many of Ms. Brockway's recommendations have already been incorporated into Duquesne's plan or that Duquesne's plan adequately addresses her concerns. Id. The remaining recommendations of Ms. Brockway and Mr. Colton result primarily from differences between the intervenors and the Company on program eligibility criteria and levels of funding, as described above. Ms. Brockway notes in her testimony that Duquesne's approach may be successful. OCA St. 6 at 13. The Commission will also oversee the Company's plan to ensure that it is successful. DLC St. 14-R at 19; Section 2804 of the Act. Thus, Duquesne's plan should be accepted by the Commission.

2. LIURP

Smart Comfort is Duquesne's low-income usage reduction program ("LIURP"). This program evolved from strictly a weatherization program into an "end use" strategy. As such, reduction measures include cost effective appliance and lighting replacements. DLC Ex. JPF-1 at 3. Again, the primary disputes between the Company and intervenors regarding this program center on eligibility and funding levels, which have been addressed above. See, e.g., DLC St. 14-R at 21; OCA St. 6 at 41-43; Pitts. St. 2 at 14-16. However, Duquesne agrees with Mr. Colton about the need to further link its Smart Comfort and CAP programs and is taking steps to do that now. DLC St. 14-R at 22; Pitts. St. 2 at 16-17. Thus, Duquesne's plan should be accepted as proposed.

3. Renewables

The Company currently does not have, and it did not propose, a specific renewable resource plan. Moreover, the Guidelines (at 30) do not require the implementation of a specific plan but allow for a flexible approach to be adopted by the Company. DLC St. 14-R at 25. Duquesne continuously evaluates new technologies for its Smart Comfort program and will incorporate promising technologies into its programs. DLC Ex. JPF-1 at 4. However, Ms. Brockway's suggestion of a photovoltaic program should not be accepted. OCA St. 6 at 43-47. Pittsburgh is too cloudy (only 42% of possible sunshine) and the payback period is too long (14 years) for such a program to be efficient or cost-effective. DLC St. 14-R at 25-26.

D. Energy Conservation

As noted above, Duquesne's Smart Comfort program includes energy conservation measures. This program is very successful and is being imitated by other utilities. DLC St. 14-R at 11; OCA St. 6 at 20-21. Duquesne proposes to continue this program at current funding levels. DLC St. 14-R at 11. If Duquesne determines that additional funds are required due to increased needs, Duquesne will seek Commission approval for rate cap relief to collect additional funds for universal service programs. Id. at 6. This flexible approach is fair and prudent, and should be adopted by the Commission.

XI. CUSTOMER EDUCATION

A. Scope of Customer Education

1. State-Wide v. Company Specific

There should be state-wide customer education as well as local, company-specific efforts. DLC St. 6-R at 25. The only issue seems to be Duquesne's role in such communication efforts, which is discussed in the next section.

2. Role of EDC

The issue is whether Duquesne should have a role in consumer education. Duquesne position is that "the responsibilities for customer education should be shared between the Commission and the EDU." DLC St. 6-R at 27 (emphasis in original); see also PECO Energy, slip op. at 156. However, the OCA, Enron and the Environmentalists support a centralized approach without EDU participation that would be led by the Commission or a neutral third body. See OCA St. 5 at 23-24; Enron St. 4 at 28; Enron St. 4.1 at 13; Environ. St. 2 at 25.

The intervenors' "one-size fits all" education program is contrary to the Act, and is inadequate in light of PECO Energy and the Consumer Education Program Rulemaking.[64] "[T]he Act contemplates that all consumers throughout the

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[64] Creation and Implementation of a Statewide Consumer Education Program for (continued...)

Commonwealth be educated on a statewide and local basis so that they fully understand their choices in obtaining electric service." PECO Energy, slip op. at 156 (emphasis added); see also Consumer Education Rulemaking at 1. The Commission has "recognized that consumer education at the local level is extremely important". Consumer Education Rulemaking at 5. Indeed, in PECO Energy, the Commission expressly noted that "participation in a statewide plan does not exonerate PECO from all its consumer education duties" and included a laundry list of specific educational obligations. PECO Energy, slip op. at 155.

B. Implementation Issues

The OCA and the City of Pittsburgh assert that Duquesne's evaluation procedures for its customer education program are insufficient. OCA St. 5 at 6; OCA St. 5-S at 2; Pitts. St. 2 at 26. Duquesne believes that it has devised a plan, as described by Company witness Hoffman, to evaluate the efficacy of its customer education plan. DLC St. 6-R at 23-24. Even though the Act is silent regarding specific evaluation procedures, "Duquesne recognizes that the ongoing evaluation and adjustment of its consumer education efforts are crucial to the introduction of customer choice." Id. at 24.

(...continued)
Electric Restructuring in the Commonwealth of Pennsylvania, Docket No. M-00981036, adopted on January 15, 1998 (Consumer Education Rulemaking).

C. Funding Levels and Recovery

The key issue is whether Duquesne recovers the costs of any customer education program required by the Commission. If the Commission requires Duquesne to increase education funding during the transition period, Duquesne should be permitted to recover those incremental expenses as transition costs. DLC St. 6-R at 14-15. Under traditional cost of service principles, the Company should be entitled to recover its costs for expenses incurred in the transition to restructuring and which exceed the cost of service. Id. Since the PECO Order and the Consumer Education Rulemaking contemplate cost recovery by the EDUs for consumer education expenses, the Commission should permit Duquesne to "treat these incremental expenses as transition costs and recover them through the appropriate mechanism." Id.

XII. MISCELLANEOUS ISSUES

N/A

XIII. CONCLUSION

For all the foregoing reasons, the Judge should adopt Duquesne's Customer Choice Plan consistent with the arguments and recommendations provided herein and the testimony of its witnesses.

Respectfully submitted,

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Dated: February 9, 1998

SUMMARY OF
STRANDED COSTS
($000)

	Company Claim	Adjustments	Adjusted Amount
Nuclear	934,400		
Fossil	607,290		
Regulatory Assets	357,280		
Total Net Present Value (NPV) in 1999 $	**1,898,970**		
PUC Jurisdictional Percent	99.9%		

STRANDED COST
CALCULATION - NUCLEAR
($000)

	Company Claim	Adjustments	Adjusted Amount
a. Net Book Value[1]	**788,590**		
b. (Market Value)[2]	(7,200)		
c. PV of Nuclear Decommissioning[3]	57,400		
d. PV of Costs Independent of Operation[4]	95,610		
e. Net Present Value (NPV) in 1999 $ (a+b+c+d)	**934,400**		
Discount Rate	7.832%		
PUC Jurisdictional Percent	99.9%		

STRANDED COST
CALCULATION - FOSSIL
($000)

	Company Claim	Adjustments	Adjusted Amount
a. Net Book Value[5]	**448,370**		
b. (Market Value)[6]	(20,200)		
c. PV of Fossil Decommissioning[7]	66,500		
d. PV of Costs Independent of Operation[8]	112,620		
e. Net Present Value *(NPV) in 1999 $* **(a+b+c+d)**	**607,290**		
Discount Rate	7.832%		
PUC Jurisdictional Percent	99.9%		

STRANDED COST
CALCULATION – REGULATORY ASSETS
($000)

	Company Claim[9]		Adjustments	Adjusted Amount
	Gross	Net		
a. Regulatory Tax Receivable (SFAS 109)	236,480	179,000		
b. Post-2005 Unamortized Debt Costs	29,920	19,040		
c. Pre-2006 Unamortized Debt Costs	16,760	9,800		
d. Deferred Rate Synch. Costs	25,370	23,500		
e. Deferred Employee Costs	13,830	13,830		
f. Deferred Nuclear Maintenance	3,250	1,900		
g. DOE Decommissioning	5,580	3,250		
h. Deferred Coal Costs	13,500	13,500		
i. Deferred Caretaker Costs	6,770	3,920		
j. BV2 Training Costs	2,420	1,580		
k. Low Level Radioactive Waste	2,270	2,270		
l. Coal Cost Equalization	120	120		
m. Pre-Accrued Nuclear Outages	17,600	10,290		
n. SFAS 106 Deferral	3,280	1,920		
o. Deferred Fuel Costs	11,510	6,730		
p. Other Regulatory Assets	530	530		
q. BV2 Sale/Leaseback Premium	N/A	N/A		
r. Gain on Sale Leaseback Tax Effect	55,130	55,130		
s. Deferred Rate Synch. Tax Effect	210	210		
t. Beaver Valley 2 Tax Effect	170	170		
u. SFAS 109 Plant	N/A	N/A		
v. Other Transition Expenses	18,100	10,590		
w. Net Present Value (NPV) in 1999 $ (Sum of a. to v.)		**357,280**		
PUC Jurisdictional Percent		99.9%		
Deferred Taxes on Regulatory Assets		105,520		

Footnotes to Appendix A

[1] Net Book Value of Nuclear Generation and Fossil Generation ($MM) is derived as follows:

	Nuclear	Fossil	Total	Source
Net Plant	763.62	606.91	1370.53	DLC Ex. DJC-21 at 33
(Deferred Income Taxes)	(239.89)	(148.62)	(388.51)	DLC Ex. DJC-21 at 33
(Investment Tax Credit)	(46.78)	(17.63)	(64.41)	DLC Ex. DJC-21 at 33
	(286.67)	(166.25)	(452.92)	Sum
Net Book Value of Gen. Plant	476.95	440.66	917.61	Sum
M&S and Fuel Related Sunk Costs	33.40	7.71	41.11	DLC Ex. DJC-13
PV of BV2 Lease Expense	475.57		475.57	DLC Ex. DJC-15 at 15 (see below)
(Deferred Income Taxes)	(197.33)		(197.33)	Product (.414935)
	278.24		278.24	Sum
Net Book Value	**788.59**	**448.37**	**1236.96**	**Sum**

PV of BV2 Lease Payments	**539.20**	**DLC Ex. DJC-15 at 15**
(Gross Accelerated Amortization)	(75.00)	DLC St. 2 at 11
Additional Deferred Pilot Costs	11.37	DLC St. 2-R at 30
(Net Accelerated Amortization)	(63.63)	Sum
PV of BV2 Lease Expense	475.57	Sum

[2] DLC Ex. DJC-20 at 2.

[3] DLC Ex. DJC-20 at 2.

[4] DLC Ex. DJC-13 and OCA CX Ex. 1.

[5] See footnote 1 above.

[6] DLC Ex. DJC-20 at 2.

[7] DLC Ex. DJC-20 at 2.

[8] DLC Ex. DJC-13 and OCA CX Ex. 1.

[9] See restated DJC-10 and NPV calculation for regulatory assets not included in ratebase (items d, e, g, m, n, o, and s) attached.

Restated Exhibit No. DJC-10
(w/ Gross and Def. Tax)
(All PV Amounts)

Duquesne Light Company

Summary of Stranded Cost Estimates
As of December 31, 1998
($ Millions)

		DLCo			OCA			OTS			DII			HSS/ARI		
		Gross	Def. Tax	Net	Gross	Def. Tax	Net	Gross	Def. Tax	Net	Gross	Def. Tax	Net	Gross	Def. Tax	Net
Generating Plant																
Net Book Value of Gen. Plant	*	$1,370.53	$452.92	$917.61	$1,365.94	$452.92	$913.02	$1,263.37	$411.34	$852.03	$1,370.53	$452.92	$917.61	N/A	N/A	N/A
Working Capital		0.00	0.00	0.00	61.53	0.00	61.53 (5)	0.00	0.00	0.00	61.53	0.00	61.53 (5)	N/A	N/A	N/A
M&S and Fuel-Related Sunk Costs	*	41.11	0.00	41.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A	N/A	N/A
PV of BV2 Lease Expense (1)	*	475.57	197.33	278.24 (1)	513.36	213.01	300.35 (6)	490.87	203.68	287.19 (8)	475.57	197.33	278.24	N/A	N/A	N/A
Net Book Value		1,887.21	650.25	1,236.96	1,940.83	665.93	1,274.90	1,754.24	615.02	1,139.22	1,907.63	650.25	1,257.38	N/A	N/A	N/A
P V of Decommissioning		123.90	0.00	123.90	44.47	0	44.47	45.10	0.00	45.10	42.96	0.00	42.96	N/A	N/A	N/A
PV of Costs Independent of Operation	*	208.23	0.00	208.23	0	0	0.00	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	0.00
Estimated Market Value	*	(46.83)	(19.43)	(27.40)	(670.10)	(278.05)	(392.05) (10)	N/A	N/A	N/A	(219.17)	(90.94)	(128.23)	N/A	N/A	N/A
Stranded Generating Plant		2,172.51	630.82	1,541.69	1,315.20	387.88	927.32	N/A	N/A	N/A	1,731.42	559.31	1,172.11	0.00	0.00	0.00
Regulatory Assets				(2)			(7)			(7)			(7)			(7)
SFAS 109	*	$236.48	$57.48	$179.00	$236.48	$57.48	$179.00	$236.48	$57.48	$179.00	$236.48	$57.48	$179.00	$0.00	$0.00	$0.00
Post-2005 - Unamortized Debt Cost	*	29.92	10.88	19.04	29.34	10.67	18.67	29.92	10.88	19.04	0.00	0.00	0.00	0.00	0.00	0.00
Pre-2006 - Unamortized Debt Cost	**	16.76	6.96	9.80	16.43	6.82	9.61	16.76	6.96	9.80	0.00	0.00	0.00	16.76	6.96	9.80
Deferred Rate Sync. Costs		25.37	1.87	23.50 (3)	20.60	1.52	19.08	25.37	1.87	23.50	24.60	1.81	22.79	0.00	0.00	0.00
Deferred Employee Costs		13.83	0.00	13.83	11.06	(3.18)	14.24	13.83	0.00	13.83	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Nuclear Maintenance	*	3.25	1.35	1.90	3.25	1.35	1.90	3.25	1.35	1.90	3.25	1.35	1.90	3.25	1.35	1.90 (9)
DOE Decom and Decon.		5.58	2.33	3.25	4.46	1.86	2.60	5.58	2.33	3.25	5.58	2.33	3.25	5.58	2.33	3.25 (9)
Deferred Coal Costs	*	13.50	0.00	13.50	0.00	0.00	0.00	13.50	0.00	13.50	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Caretaker Costs	*	6.77	2.85	3.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BV2 Training Costs	*	2.42	0.84	1.58	2.42	0.84	1.58	2.42	0.84	1.58	2.42	0.84	1.58	2.42	0.84	1.58 (9)
Low Level Rad. Waste	*	2.27	0.00	2.27	2.27	0.00	2.27	2.27	0.00	2.27	2.27	0.00	2.27	2.27	0.00	2.27 (9)
Coal Cost Equalization	*	0.12	0.00	0.12	0.12	0.00	0.12	0.12	0.00	0.12	0.12	0.00	0.12	0.12	0.00	0.12 (9)
Other	*	0.53	0.00	0.53	0.53	0.00	0.53	0.53	0.00	0.53	0.74	0.00	0.74	0.53	0.00	0.53 (9)
Pre-Accrue Nuclear Outages		17.60	7.31	10.29	0.00	0.00	0.00	17.60	7.31	10.29	0.00	0.00	0.00	0.00	0.00	0.00
Gain on Sale/Leaseback	*	55.13	0.00	55.13	55.13	0.00	55.13	55.13	0.00	55.13	55.13	0.00	55.13	55.13	0.00	55.13 (9)
Deferred Rate Sych. Costs (Tax)		0.21	0.00	0.21	0.17	0.00	0.17	0.21	0.00	0.21	0.21	0.00	0.21	0.00	0.00	0.00
BV-2 (Tax)	*	0.17	0.00	0.17	0.17	0.00	0.17	0.17	0.00	0.17	0.17	0.00	0.17	0.17	0.00	0.17 (9)
Deferred Fuel Cost		11.51	4.78	6.73	9.20	3.82	5.38	11.51	4.78	6.73	11.51	4.78	6.73	11.51	4.78	6.73 (9)
Transition Costs	*	18.10	7.51	10.59	18.20	7.51	10.59	18.10	7.51	10.59	9.80	4.07	5.73	0.00	0.00	0.00
SFAS 106		3.28	1.36	1.92	2.62	1.09	1.53	3.28	1.36	1.92	0.00	0.00	0.00	0.00	0.00	0.00
SFAS 109 Plant	*	0.00	0.00	0.00 (4)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Regulatory Assets		462.80	105.52	357.28	412.46	89.88	322.57	456.03	102.67	353.36	352.28	72.66	279.62	97.74	16.26	81.48
Total Stranded Cost		$2,635.31	$736.34	1898.9700	$1,727.66	$477.77	$1,249.89	N/A	N/A	N/A	$2,083.70	$631.97	$1,451.73	$97.74	$16.26	$81.48
Percent of Company Claim		100.00%	100.00%	100.00%	65.56%	64.88%	65.82%	N/A	N/A	N/A	79.07%	85.83%	76.45%	3.71%	2.21%	4.29%

* Items included in rate base for stranded cost.
** Included in Interest Expense.

1) Includes premiums and unamortized debt costs.
2) Duquesne's Regulatory Assets are shown net of deferred taxes.
3) Reflects adjustment based on DII proposal.
4) Included in plant as of 12/31/98.
5) Item not claimed by the Company.
6) Net of tax amount based on OCA gross amount of $513.36 million.
7) Regulatory assets adjusted to reflect net of deferred tax amounts.
8) PV is based on OTS recommended cost of capital.
9) Not specifically addressed by HSS/ARI.
10) Includes OCA's proposed productivity ($25.32) and life extension benefits ($170.72).

Duquesne Light Company
Net Present Value of Regulatory Assets not Included in Rate Base
(Items d, e, g, m, n, o, and s)

Discount Rate **7.83%** **1/2 year Convention**

Regulatory Assets	Gross	Year	Amort.	PV	PV Sum
Deferred Rate Sync. Costs	32.66	0.5	4.67	4.49	25.37
Source : DLC Ex. DJC-15 at 1		1.5	4.67	4.17	
		2.5	4.67	3.86	
		3.5	4.67	3.58	
		4.5	4.67	3.32	
		5.5	4.67	3.08	
		6.5	4.67	2.86	
Deferred Employee Costs	17.80	0.5	2.54	2.45	13.83
Source : DLC Ex. DJC-15 at 2		1.5	2.54	2.27	
		2.5	2.54	2.11	
		3.5	2.54	1.95	
		4.5	2.54	1.81	
		5.5	2.54	1.68	
		6.5	2.54	1.56	
DOE Decom and Decon.	7.18	0.5	1.03	0.99	5.58
Source : DLC Ex. DJC-15 at 3		1.5	1.03	0.92	
		2.5	1.03	0.85	
		3.5	1.03	0.79	
		4.5	1.03	0.73	
		5.5	1.03	0.68	
		6.5	1.03	0.63	
Pre-Accrue Nuclear Outages	22.65	0.5	3.24	3.12	17.60
Source : DLC Ex. DJC-15 at 8		1.5	3.24	2.89	
		2.5	3.24	2.68	
		3.5	3.24	2.49	
		4.5	3.24	2.30	
		5.5	3.24	2.14	
		6.5	3.24	1.98	
Deferred Rate Sych. Costs (Tax)	0.27	0.5	0.04	0.04	0.21
Source : DLC Ex. DJC-15 at 9		1.5	0.04	0.03	
		2.5	0.04	0.03	
		3.5	0.04	0.03	
		4.5	0.04	0.03	
		5.5	0.04	0.03	
		6.5	0.04	0.02	
Deferred Fuel Cost	14.81	0.5	2.12	2.04	11.51
Source : DLC Ex. DJC-15 at 9		1.5	2.12	1.89	
		2.5	2.12	1.75	
		3.5	2.12	1.63	
		4.5	2.12	1.51	
		5.5	2.12	1.40	
		6.5	2.12	1.30	
SFAS 106	4.22	0.5	0.60	0.58	3.28
Source : DLC Ex. DJC-15 at 11		1.5	0.60	0.54	
		2.5	0.60	0.50	
		3.5	0.60	0.46	
		4.5	0.60	0.43	
		5.5	0.60	0.40	
		6.5	0.60	0.37	

General Note on Restatement of Certain Regulatory Assets

With respect to both (i) the tables included with the Main Brief, and (ii) a Restated Exhibit DJC-10, which states the positions of the major parties in a consistent manner, the following note applies:

> The Regulatory Assets have been restated on a NPV basis pursuant to a discussion with OCA, consistent with the detail provided in DLC Ex. DJC-15. Note that items d, e, g, m, n, o, and s have been restated at a lower NPV (calculated at 7.83%) than the corresponding book values (net of deferred tax) shown in DLC Ex. DJC-10. These items had not been included in rate base in DLC Ex. DJC-21 for purposes of calculating a return during the transition period, and would have been amortized on a straight-line basis under Duquesne's proposed 2804(4)(v) rate cap plan. Stating these items on a NPV basis is consistent with earning a return on the unamortized balance of these stranded costs, and thus the NPV is less than the book value stated in DLC Ex. DJC-10. The effect of restating these items is to present the claimed amount for Regulatory Assets (net of deferred tax) as $357.28 MM rather than the $374.45 MM stated in DLC Ex. DJC-10. If Duquesne's cost of capital were used to make revenue requirements on this $357.28 MM, the present value of the CTC revenue requirements for Regulatory Assets would be the same as indicated by Duquesne in its Rebuttal case. In addition, in each case the annual amortization under Duquesne's proposed 2804(4)(v) rate cap plan for these particular regulatory assets (as set forth in DLC Ex. DJC-15) has been discounted to a NPV at December 31, 1998 using the half-year discounting convention in DLC Ex. DJC-14. Details of this restatement on a NPV basis are set out in the attachment referenced in note 9 to the tables contained in DLC Appendix A.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00974104**
	)	
Duquesne Light Company Application for Approval of a Restructuring Plan Pursuant to 66 Pa. C.S. § 2806(d)	)	

CERTIFICATE OF SERVICE

I hereby certify that I have this day served two copies of the Main Brief, by overnight mail, upon the participants on the attached service list in accordance with Section 1.54 of the Commission's regulations.

Dated this 9th day of February, 1998.

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