

COMMONWEALTH OF PENNSYLVANIA



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OFFICE OF SMALL BUSINESS ADVOCATE

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November 19, 1997

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HAND DELIVERED

James J. McNulty, Secretary
Pennsylvania Public Utility Commission
Room B-20, North Office Building
P. O. Box 3265
Harrisburg, PA 17105-3265

ORIGINAL

Re: Application of Duquesne Light Company
for Approval of its Restructuring Plan
Under Section 2806 of the Public Utility Code
Docket No. R-00974104

Dear Secretary McNulty:

I am delivering for filing today the original plus three copies of the Reply Comments of the Office of Small Business Advocate regarding the Third Compliance Filing of Duquesne Light Company.

A copy has been served today on all known parties in this proceeding. A Certificate of Service to that effect is enclosed.

Sincerely,

Angela T. Jones
Assistant Small Business Advocate

Enclosures

cc: Cheryl Walker Davis, Director
Office of Special Assistants

Robert Bennet, FUS

Parties of Record
Mr. Brian Kalcic

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SECRETARY'S BUREAU

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ORIGINAL

Application Of Duquesne Light :
Company For Approval Of Its :
Restructuring Plan Under : Docket No. R-00974104
Section 2806 Of The :
Public Utility Code :

OFFICE OF SMALL BUSINESS ADVOCATE
REPLY COMMENTS
REGARDING THE THIRD COMPLIANCE FILING OF
DUQUESNE LIGHT COMPANY

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By Opinion and Order in the Application to Approve Restructuring Plan Pursuant to 66 Pa. C.S. § 2806(d), Docket No. R-00974104, entered on October 16, 1998 ("Second Compliance Order"), the Pennsylvania Public Utility Commission directed Duquesne Light Company ("Duquesne" or "Company") to submit a third revised compliance filing on or before November 5, 1998, and Duquesne did so. Comments on that filing were then filed on November 12, 1998. The Office of Small Business Advocate ("OSBA") now files the following reply comments to the OCA's comments with regard to the Company's third compliance filing.

I. OCA Comments Regarding the Rate RH Shopping Credit

The OCA notes its continuing concern that the projected shopping credits for Rate RH customers will not provide residential electric heating customers with a meaningful opportunity to participate in the competitive market.¹ (OCA

¹

In particular, the OCA cites a decrease in the 1999 Rate RH shopping credit of 3.93 cents per kWh to 2.62 cents per kWh in 2000.

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comments at page 2). The OCA avers that this issue must be addressed and suggests two potential remedies.

First, the OCA suggests that it may be possible to adjust the Rate RH shopping credits at the time that divestiture proceeds are known. In the event that divestiture proceeds reduce Duquesne's stranded costs, "the CTC for Rate RH could be lowered and the shopping credit increased."² (OCA comments at page 3.) As an alternative, the OCA notes that the Commission might increase the Rate RH shopping credits to a meaningful level, and then lengthen the CTC collection period and extend the generation rate cap for Rate RH customers, as needed. (OCA comments at page 4.)

While the OSBA is sympathetic toward the OCA's concern, any resolution to the RH shopping credit dilemma must not come at the expense of other rate classes. The Commission has clearly established the amount of Duquesne's stranded costs that should be allocated to the various rate classes. In the event that the shopping credits for Rate RH customers are increased in response to the OCA's comments on Duquesne's Third Compliance Filing, the total stranded cost responsibility that has been allocated to Rate RH must nevertheless remain the ultimate responsibility of that class. 66 Pa. Code §2808(a). No amount of shifting of stranded cost responsibility away from Rate RH would be appropriate since such action would obviously violate the Competition Act as well as the Commission's prior rulings regarding stranded cost allocation.³

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It is not clear whether the OCA is advocating a greater-than-proportional reduction in Rate RH's CTC. As argued below, such action would be totally inappropriate and contrary to the Competition Act.

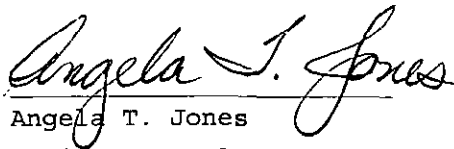
3

It appears that the OCA's alternative suggestion regarding the possible extension of the Rate RH CTC recovery period in order to resolve this problem would pass the statutory "no cost shifting" test.

II. Conclusion

On the basis of the foregoing, the Office of Small Business Advocate respectfully requests that, in the event that the shopping credits for Rate RH are increased beyond those shown in Duquesne's third compliance filing, no amount of shifting of stranded cost responsibility away from the Rate RH class be allowed.

Respectfully submitted,


Angela T. Jones

Assistant Small Business Advocate

Dated: November 19, 1998

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Duquesne :
Light Company For Approval :
Of Its Restructuring Plan : Docket No. R-00974104
Under Section 2806 Of The :
Public Utility Code :

CERTIFICATE OF SERVICE

I certify that I am serving a copy of the Reply Comments regarding the Third Compliance Filing of Duquesne Light Company on behalf of the Office of Small Business Advocate by first class mail (unless otherwise indicated) upon the persons addressed below:

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Angela T. Jones
Assistant Small Business Advocate

Date: November 19, 1998

ORIGINAL

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DOCUMENT
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Application of Duquesne Light)
Company for Approval of Restructuring)
Plan Under Section 2806 of the Public)
Utility Code _____)

Docket No. R-00974104

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**FURTHER COMMENTS OF
GREEN MOUNTAIN ENERGY RESOURCES
ON THE SUPPLIER TARIFF
THIRD COMPLIANCE FILING OF DUQUESNE LIGHT COMPANY
REGARDING STAND-ALONE RESTRUCTURING PLAN**

NOW COMES Green Mountain Energy Resources L.L.C. ("Green Mountain"), licensed as an Electric Generation Supplier at Docket No. A-110073 (June 4, 1998), and files these Further Comments to the Electric Generation Supplier Coordination Tariff of Duquesne Light Company ("Duquesne") Third Compliance Filing Regarding Stand-Alone Restructuring Plan ("Third Compliance Filing").

1. Green Mountain appreciates the process that Duquesne utilized in developing its Third Compliance Filing. However, Green Mountain feels compelled to submit these Further Comments in order to address the use of Scheduling Coordinators by Electric Generation Suppliers ("EGSs"), and the necessary changes that must be made to Duquesne's Third Compliance Filing Tariff ("Tariff") that was filed on November 5, 1998. Although Green Mountain conveyed its concerns on this issue to Duquesne during the second meeting between Duquesne and suppliers, Duquesne's November 5th tariff filing fails to address adequately the needs of EGSs' using scheduling coordinators. Green Mountain believes that this issue now needs to be resolved by the Commission.

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2. Although the proposed Duquesne Tariff includes provisions for the utilization of Scheduling Coordinators by EGSs, it became apparent during conversations at the suppliers' meetings that Duquesne is interpreting those provisions in a way that is unduly restrictive for the developing new marketplace. In particular, Green Mountain expressed its desire to have its Scheduling Coordinator sign and be responsible to Duquesne in the first instance for obligations under the OATT (and the Coordination Sales Tariff, if applicable). This is consistent with the contractual arrangements Green Mountain has made with its wholesale suppliers, which are providing all-requirements service for the customer loads of Green Mountain and are assuming Green Mountain's supply-related obligations under Duquesne's Supplier Coordination Tariff. Green Mountain believes that it is also consistent with the current language of the supplier tariff, which at Section 2.2 states that "the term 'EGS' shall apply equally to a Scheduling Coordinator for responsibilities and rights properly assigned to the Scheduling Coordinator by the EGS." Duquesne disagreed with this interpretation and said that it was unwilling to enter into such an arrangement, preferring to contract only with the EGS.

3. The basis for Duquesne's objection to Green Mountain's proposal is unclear to Green Mountain. While Duquesne expressed concern about the risk of non-delivery of power supplies, this risk is addressed perhaps more comprehensively from the EDC's perspective by the arrangement contemplated by Green Mountain. Duquesne would first be protected by the direct contract with the Scheduling Coordinator (the OATT). In addition, pursuant to Section 9.3 of the Supplier Coordination Tariff, Green Mountain would be responsible in the event that its Scheduling Coordinator failed to perform. Green Mountain is simply requesting that Duquesne look in the first instance to its Scheduling Coordinator with respect to supply obligations.

4. Of course, the Scheduling Coordinator designated by the EGS must be eligible to take service under the OATT. Green Mountain notes that Duquesne's OATT includes the following definitions:

1.3 Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Provider [Duquesne], an Eligible Customer, or the Transmission Customer required under the Tariff [OATT].

* * *

1.5 Eligible Customer: (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such services by the Transmission Provider. (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

* * *

1.39 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission [FERC], a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

Open Access Transmission Tariff of Duquesne Light Company, pp. 9-10 & 18, <<ftp://soc-dlco.lm.com/pub/Documents/DLOAW60.doc>>.

It appears that either EGSs or their scheduling coordinators qualify as an "Eligible Customer" under Section 1.5 of the Duquesne OATT. Furthermore, Duquesne's OATT contains provisions that permit the sale or assignment of transmission service obtained by an "Eligible Customer"

under the OATT. *Id.*, Sec. 2.1, pp. 78-80.¹ It is obvious that any Scheduling Coordinator who will act as a “Designated Agent” on behalf of Green Mountain in obtaining services from the Duquesne OATT will have a corresponding agreement with Green Mountain. Thus, the obligations imposed under the Duquesne OATT will effectively flow to Green Mountain regardless of whether Green Mountain’s “Designated Agent” Scheduling Coordinator is the signatory to the Duquesne OATT.

5. Allowing extensive use of Scheduling Coordinators for supply-related obligations of EGSs provides needed flexibility and lowers the barriers to entry for new entrants in the retail market, without compromising the financial interest of utilities in ensuring that supply obligations are met. Green Mountain, therefore, urges the Commission to instruct Duquesne to interpret its tariff language (which is consistent with the language in most EDC tariffs) to allow a Scheduling Coordinator that meets eligibility criteria under Duquesne’s OATT to sign and fulfill the obligations of the EGS with respect to that agreement.

6. In addition, Green Mountain believes that the proposed Duquesne Tariff provisions need to be expanded in order to include the use of multiple Scheduling Coordinators by a single EGS. Green Mountain emphasizes the point that the use of multiple Scheduling Coordinators by an EGS and the future assignment of individual Scheduling Coordinators to distinct customer groups considerably enhance the flexibility of an EGS’s power supply operations within a competitive electricity market in Pennsylvania. For instance, accommodation for multiple Scheduling Coordinators will be necessary in situations where the Scheduling Coordinator is providing full requirements service to an EGS up to a certain number of

¹ Green Mountain acknowledges that such sale or assignment of transmission service that is obtained under Duquesne’s OATT may require certain filings with and approvals by FERC.

customers or volume of load. An additional scheduling coordinator for the EGS will be needed at the time that limit is reached.

Thus, Green Mountain requests that the proposed Duquesne Tariff be modified in order to reflect the use of multiple Scheduling Coordinators by EGSs:

- 9.1 Participation Through a Scheduling Coordinator.** If an EGS chooses not to interact directly with the CAO for scheduling purposes, or cannot schedule directly with the CAO because its schedules do not meet the "whole megawatt" requirements set by the CAO for scheduling, an EGS may become a Coordinated Supplier by entering into a business arrangement with another EGS or entity that will act as a Scheduling Coordinator(s). Once this business arrangement is in place, the Scheduling Coordinator(s) will act on behalf of the EGS with regard to all load forecasting, supply scheduling, and reconciliation activities and responsibilities of the EGS required under this Tariff.

Furthermore, Green Mountain requests that the proposed Duquesne Tariff be modified through the addition of the corresponding tariff language that has been adopted by West Penn Power Company ("West Penn Power"):

- 9.6 Multiple Scheduling Coordinators.** At such time as the EDEWG incorporates a data exchange methodology for the designation of a Scheduling Coordinator for each customer, the Company will, within a reasonable time, permit multiple Scheduling Coordinators for an EGS. The EGS will be required to submit a Scheduling Coordinator Designation Form for each Scheduling Coordinator.

West Penn Power, Electric Generation Supplier Services Tariff, issued November 3, 1998, Sec. 9.6, Orig. p. No. 29 (this tariff received tentative approval by the Commission during its November 4, 1998 Public Meeting, at Docket No. R-00973981).

7. Green Mountain believes that the presence and the use of Scheduling Coordinators by EGSs should also be addressed in Section 12.4 of the proposed Duquesne Tariff. Green Mountain requests that Section 12.4 of the proposed Duquesne Tariff be modified as follows:

12.4 Guarantee of Payments. Before the Company will render service or continue to render service, the Company shall require an applicant for Coordination Service or an EGS currently receiving such service that has Bad Credit to provide a deposit in the form of a letter of credit, or other guarantee satisfactory to the Company. **If the EGS utilizes a Scheduling Coordinator to fulfill its obligations pursuant to Sections 6-9 of this Tariff related to forecasting, scheduling and settlement, the Company will make determinations and arrangements regarding security for those obligations directly with the Scheduling Coordinator at the request of the EGS.** The Company will hold the deposit as security for the payment of final bills and compliance with the Company's Rules and Regulations. In addition, the Company may require an EGS to post a deposit at any time if the Company determines that the EGS is no longer Creditworthy or has Bad Credit. An EGS shall have the right to submit to the Commission for resolution any reasonable dispute regarding such deposit sought by the Company if the EGS believes such a requirement is inappropriately based or assessed.

Similarly, Green Mountain requests the following change in Section 12.4.1 of the proposed Duquesne Tariff:

12.4.1 Amount of Deposits. The total deposit requested of the EGS and/or its Scheduling Coordinator under this tariff shall be equal to (i) \$250,000, or (ii) two months' of the EGS's Customers' forecasted MWH load multiplied by \$25.00, whichever is less. The Company, in its sole discretion, may reduce the amount of this deposit if circumstances warrant.

Plainly, the benefits derived from an EGS's use of a scheduling coordinator to provide full-requirements power supply service include the potential to align with an entity that is larger and either already has established credit relationships with EDCs covering the risk of non-delivery or has a higher level of creditworthiness. The tariff language should allow those benefits, which inure to the EDCs as well as EGSs, to be realized. As noted above, providing EGSs such flexibility will lower barriers to entry and help promote a competitive market.

WHEREFORE, Green Mountain Energy Resources respectfully requests that the Commission modify the proposed third revised compliance Electric Generation Supplier Coordination Tariff of Duquesne Light Company.

Respectfully submitted,



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DATED: November 20, 1998

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I hereby certify that I have this day served true copies of the Further Comments of Green Mountain Energy Resources, L.L.C. to Duquesne Light Co.'s Third Compliance Filing upon the following participants in accordance with the requirements of 52 Pa. Code § 1.54.

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November 20, 1998

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Via Overnight Mail

NOV 20 1998

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Re: Duquesne Light Company
Docket No. R-00974104

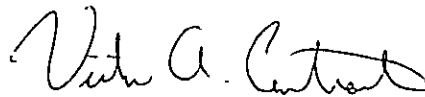
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Dear Mr. McNulty:

Enclosed is an original and nine copies of the Third Compliance Filing of Duquesne Light Company regarding Stand-Alone Restructuring Plan. 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,



Victor A. Contract
Counsel to Duquesne Light Company

Enclosure

SRB

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION
PENNSYLVANIA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Pennsylvania Public Utility)
Commission,)
v.)
Duquesne Light Company)
Application to approve)
restructuring plan pursuant)
to 66 Pa. C.S. § 2806(d))

Docket No. R-00974104

ORIGINAL

REPLY COMMENTS OF DUQUESNE LIGHT COMPANY REGARDING
THIRD COMPLIANCE FILING OF DUQUESNE LIGHT COMPANY
STAND-ALONE RESTRUCTURING PLAN

DOCKETED

Duquesne Light Company ("Duquesne") hereby requests leave to NOV 23 1998

submit limited reply comments to the comments filed by the Office of Consumer Advocate ("OCA") and Duquesne Industrial Intervenors ("DII") on the Third Compliance Filing dated November 5, 1998. By filing limited reply comments, Duquesne is attempting to limit its comments by not rearguing matters previously addressed and is not thereby waiving any argument or position addressed in Duquesne's previous filings at the Commission.

1. Sales Volume & Realized Return

The OCA requests the Commission to direct Duquesne to provide a full explanation of the sales decline from 1996 test year volumes. OCA Comments at 1-2. The OCA notes that, when using the 1999 sales volumes as opposed to the

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1996 levels, the sales volumes for Rate RS and Rate RH classes actually decline, and as a result, would increase the average T&D rate cap numbers for these classes. OCA Comments at 1-2. OCA's comments are attempting to open a previously decided issue. The Commission ordered Duquesne to use a total test year volume of 12,519,000,000 kWh in computing unbundled T&D rates. Second Compliance Order at 9-10.¹ The Company, as directed in the Second Compliance Order, utilizes the 1999 sales volumes to compute unbundled T&D rates in its Third Compliance Filing. OCA should not be surprised by this outcome considering that the projected sales volume information was provided in response to OCA-4-005 and OCA-4-006. The Company already has explained why it believed it made little sense to compute rates using different data -- i.e., 1996 costs and 1999 sales volumes. The Commission rejected our arguments, and directed the Company, without detailed explanation, to use the OCA's 1999 volumes.

The OCA also comments that the shopping credit for Rate RH customers "will not provide a meaningful opportunity to participate in the competitive market". OCA Comments at 2. The OCA expresses concern about the drop in the shopping credit for Rate RH customers in 2000. The OCA recommends adjust-

¹ In its first two compliance filings Duquesne developed unbundled T&D rates on the basis of 1996 cost, 1996 sales volumes and 1996 class realized rates of return.

ing the shopping credits at the time the proceeds are known. The OCA's position should, and indeed already has been, rejected. First, the Commission has already held that shopping credits for each class should remain fixed during the transition period. Final Order at 212-13. Second, the Commission also has held that the shopping credit is a residual after the close of the auction and that the purpose of this proceeding is therefore not to litigate the appropriate shopping credit for each class. Final Order at 197; First Compliance Order at 12. Third, adopting OCA's proposal would add uncertainty to the POLR auction because potential POLR bidders would not know with certainty the value of the shopping credits. This uncertainty likely would reduce the value of the POLR service to potential bidders and thereby reduce the proceeds from the proposed auction.

The OCA also appears to allege that the realized return should be negative 3% return for rate class RH, which would raise the shopping credit after 1999. Duquesne disagrees. OCA attempts to rely upon outdated assumptions and outdated data. The negative 3% rate of return was since revised in this proceeding. Duquesne originally computed the realized rate of return in response to OSBA interrogatory 02-22 which contained an ECR roll-in based on average fuel and purchased power cost of \$14.70/MWh. The Commission rejected this calculation and the allocation of distribution related income taxes (which has since been cor-

rected). In fact, realized rate of return calculations for all classes have changed since that earlier response.

Finally, and as an additional reason to reject the OCA's position, if the Commission chose to adopt the OCA's proposal for RH class customers, the Commission would have to reopen the determination of shopping credits and associated CTC recovery for all rate classes. At this stage in the proceedings, it is too late to revisit settled issues that could jeopardize the start of competition on January 1, 1999.

2. Transmission & Distribution Rate Cap

DII states that the Company's proposed Tariff 18 inappropriately decreases from 20 days to 15 days the bill payment period for customers on Rate Schedules L, HVPS, GS/GM, GMH, GL & GLH. DII Comments at 5-6. The currently effective Tariff 17 provides for payment by those classes after 15 days. Duquesne has intended to maintain the same payment period in the proposed Tariff 18. The payment period was inadvertently changed to 20 days (from 15 days) in the Second Compliance Filing (Tariff 18). Upon noticing this inadvertent revision, Duquesne corrected the mistake in the Third Compliance Filing and revised the payment schedule to 15 days. Duquesne submits that this should not be considered a material revision given that the presently effective tariff also provides for payment within 15 days.

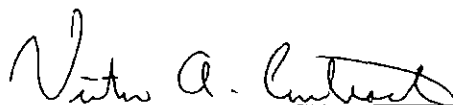
3. Supplier Tariff

DII states that Duquesne should not provide information beyond the information that Duquesne provided to the supplier in the initial electronic data exchange between the Company and the EGS. DII Comments at 7-8. Duquesne intends to release only information that is authorized by the Customer and/or the PUC (through the EDEWG regulations).

In addition, Duquesne revises the definition of "Coordination Services Charges". Duquesne inadvertently failed to remove reference to the term "Coordination Sales Tariff" in this definition. The revised definition, and a black-lined version thereof, is attached as Attachment A.

WHEREFORE, Duquesne's Third Compliance Filing should be accepted without modification or condition for the reasons stated above.

Respectfully submitted,



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Dated: November 20, 1998

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

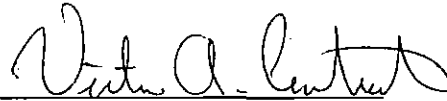
**Pennsylvania Public Utility)
Commission,)
v.)
Duquesne Light Company)
Application to approve)
restructuring plan pursuant)
to 66 Pa. C.S. § 2806(d))**

Docket No. R-00974104

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing document was served, by first-class mail, upon the participants on the attached service list in accordance with Section 1.54 of the Commission's regulations.

Dated this 20th day of November, 1998.



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**ATTACHMENT A
SUPPLIER TARIFF REVISION**

Duquesne Light Company

Original Page No. 5

provision of Coordination Services.

Coordination Services - those services that permit the type of interface and coordination between EGSs and the Company in connection with the delivery of Competitive Energy Supply to serve Customers located within the Company's service territory including: load forecasting, certain scheduling-related functions and reconciliation services, those transmission and Ancillary services offered under the OATT tariff, and transmission losses and distribution losses.

Coordination Services Charges - all Charges stated in the Charges section of this Tariff, or the OATT, that are billed by the Company for Coordination Services performed hereunder.

Coordinated Supplier - an Electric Generation Supplier that has appointed a Scheduling Coordinator as its designated agent for the purpose of coordinating its energy supply with the CAO.

Creditworthy - a creditworthy EGS pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the PaPUC. To determine whether an EGS is creditworthy, the Company will evaluate the EGS's record of paying Company charges, and may also take into consideration the EGS's credit history.

Customer(s) - any person, municipality, partnership, association, or corporation receiving Competitive Energy Supply from an Electric Generation Supplier in accordance with the Competition Act.

Customer Choice Internet Site - a Company Internet site with a Uniform Resource Locator (URL) of <http://www.customer-choice.com>.

Deliver - to "Deliver" a document or other item under this Tariff shall mean to tender by certified mail, hand delivery, or overnight express package delivery service.

Delivery - the actual delivery of energy with respect to an energy schedule.

Issued _____, 1998
Effective _____, 1998

Duquesne Light CompanyOriginal Page No. 5

provision of Coordination Services.

Coordination Services - those services that permit the type of interface and coordination between EGSs and the Company in connection with the delivery of Competitive Energy Supply to serve Customers located within the Company's service territory including: load forecasting, certain scheduling-related functions and reconciliation services, those transmission and Ancillary services offered under the OATT tariff, and transmission losses and distribution losses.

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Coordinated Supplier - an Electric Generation Supplier that has appointed a Scheduling Coordinator as its designated agent for the purpose of coordinating its energy supply with the CAO.

Creditworthy - a creditworthy EGS pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the PaPUC. To determine whether an EGS is creditworthy, the Company will evaluate the EGS's record of paying Company charges, and may also take into consideration the EGS's credit history.

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Draft November 20, 1998 - 9:10 AM

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ORIGINAL

Pennsylvania Public Utility)
Commission,)
v.)
Duquesne Light Company)
Application to approve)
restructuring plan pursuant)
to 66 Pa. C.S. § 2806(d))

Docket No. R-00974104

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU
**REPLY COMMENTS
OF DUQUESNE LIGHT COMPANY
ON THE GENERATION AUCTION PLAN**

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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.S. § 2806(d))	

**REPLY COMMENTS
OF DUQUESNE LIGHT COMPANY
ON GENERATION AUCTION PLAN**

Pursuant to the Secretarial Letter dated October 27, 1998, Duquesne Light Company ("Duquesne") hereby submits this reply to the comments of the intervenors on the Generation Auction Plan.

INTRODUCTION

The comments of the intervenors fall into three general categories. The first, represented by the Office of Consumer Advocate ("OCA") and Duquesne Industrial Intervenors ("DII"), generally support the Auction Plan, particularly the Generation Exchange with FirstEnergy Corp. As to the "swap" with FirstEnergy, the OCA states:

[T]he swap would permit the divestiture to proceed in a timely fashion by eliminating uncertainty created by shared ownership interests and agreements. Together with the value created by sole ownership and control of the plants, it is OCA's view that the swap is likely to create greater value for Duquesne's ratepayers than would a divesti-

ture of its partial, minority ownership in its current plants. Furthermore, OCA recognizes that this agreement is an integrated package and that other assets cannot be substituted.

Additionally, FirstEnergy's minimum financial guarantee provides an "insurance policy" that consumers will not incur a higher level of stranded costs than the level determined by the Commission. This is an extremely important assurance in an infant marketplace for generating assets and, while it does not ensure that ratepayers are better off as a result of the asset exchange, it at least means that they won't be worse off than under the PUC's administrative determination of stranded costs, and provides an important protection from that volatility. It is also worth pointing out, as further discussed below, that the Agreement in Principle caps Duquesne's nuclear decommissioning liability at the level funded at the time of transfer. Finally, FirstEnergy's agreement not to bid on the plants when they come up for auction helps ensure that the ECAR market will not become even more concentrated as a result of the asset swap.

OCA Comm. at 9-10.¹

The only significant caveat to the support of the OCA and DII (other than disagreements with Duquesne over discrete issues, *see infra*) is their understandable desire to have the opportunity to review and comment on the *final* agreements with FirstEnergy, the final agreements with the winning bidder(s) in the auction, and any agreements related to the provider of last resort ("POLR") service. Duquesne understands this concern and is *not* requesting final approval at this time

¹ The DII states that "the proposed capacity swap may be in the best interests of Duquesne ratepayers" and supports a Commission order permitting "Duquesne to continue pursuing a capacity swap with FirstEnergy." DII Comm. at 10, 12.

of any of these arrangements. Rather, Duquesne is requesting a Commission order finding that (i) the Auction Plan is consistent with the public interest on the terms and conditions proposed, and (ii) directing Duquesne to commence implementation of the Auction Plan, subject to final Commission approval of all matters within its jurisdiction. To this end, Duquesne has drafted a proposed order for the Commission that would, consistent with the positions of the OCA and DII, authorize Duquesne to proceed with the auction subject to further collaboration with the intervenors and the subsequent filing of any final agreements with the Commission. *See Appendix A.*

The second category of comments, represented by the Environmentalists and Hospital Shared Services/Administrative Resources, Inc. ("HSS"), advocate a one-sided auction where ratepayers automatically retain the benefits of the auction if generation values are high, but if the values turn out to be low, Duquesne and its shareholders would be penalized for any supposed defects in implementing the auction. HSS Comm. at 3; Environ. Comm. at 5-7. The Environmentalists go even further, asserting that "the Commission should allocate much of the transaction cost to the shareholders" regardless of the level of auction proceeds. Environ. Comm. at 9.

These parties are wrong to believe that such a one-sided approach is costless to ratepayers. Duquesne will not agree to close the auction transactions

unless it has reasonable assurance that, as found by Judge Corbett and approved by the Commission, Duquesne will fully recover its stranded costs through the auction. Thus, any *post-hoc* review would only increase regulatory impediments to closing, thereby potentially reducing the pool of bidders and, even for those willing to participate, causing them to discount their bids to reflect the uncertainty as to whether and when the transaction would close. Duquesne therefore strongly urges the Commission to reject such counterproductive proposals and adopt the position of the OCA: "The OCA agrees with the Company that to the extent the Commission finds Duquesne's auction procedures and protocols to be reasonable at this time, the Commission should not conduct a *post-hoc* review of those procedures and protocols." OCA Comm. at 34. In this regard, it is notable that no party has objected to the auction protocols set forth in Section II of the Auction Plan. There being no dispute over them, the Commission should approve those protocols and authorize Duquesne to commence the Auction, subject to the OCA's suggestion (with which Duquesne agrees) that Duquesne "file periodic reports with the Commission and the parties to assure that the process is progressing as intended." OCA Comm. at 34.

The third category of comments, represented by System Council U-10, International Brotherhood of Electrical Workers ("IBEW"), and certain state legislators, advocate putting the auction on hold until "very serious labor issues" have been "resolved." IBEW Supp. Comm. at 5. This approach has no merit.

Duquesne has unequivocally stated that "union employees will be protected by the terms of the existing Collective Bargaining Agreement ("CBA") between Duquesne and the Union." Letter of J. Moot to J. McNulty, November 5, 1998, page 2. This contract explicitly provides protections to union members in the event of a divestiture of generation. IBEW Supp. Comm. at 2. Having negotiated these protections, the IBEW must now live by them (particularly given that it has chosen to reject all of Duquesne's offers to amend that contract). It thus can no longer contend that "Duquesne has not addressed the effect of its plan on employees" (IBEW Supp. Comm. at 5); those "effects" – whatever their scope – will flow directly from provisions of the CBA that the Union itself negotiated.

In fact, the IBEW readily concedes that "it is *not* asking this Commission to resolve this labor dispute" (IBEW Supp. Comm. at 4) (emphasis in original) and it "is *not* seeking to negotiate [labor] issues before this Commission." IBEW Comm. at 10. But, of course, if the Commission has no jurisdiction to resolve these labor matters,² it cannot later be asked to "ensure that the result is in the public

² Notably, the IBEW does not contend, nor could it, that the Commission has authority to resolve labor-related matters. Rather, the Customer Choice Act requires only that Duquesne describe "the impacts of the proposed [restructuring] plan on the utility's employees" (66 Pa.C.S. § 2806(e)) and provides that, if the plan "entail[s] the closure of facilities or reduction in employee levels," the utility "may provide severance, retraining, early retirement and outplacement services" and "[s]uch transition costs may be recoverable under
(continued...)

interest." IBEW Supp. Comm. at 5. The Commission should therefore reject the position of the IBEW and permit the Auction to proceed. To do otherwise will clearly harm ratepayers, depriving them of any opportunity to take advantage of the current favorable market conditions for the sale of generating assets. As the OCA acknowledges, there is no certainty that these current market conditions will continue. OCA Comm. at 10. The IBEW's comments simply ignore the substantial harm that its position may cause ratepayers and are otherwise without merit.

I. GENERATION EXCHANGE WITH FIRSTENERGY

A. "Final Approval"

The OCA and other parties request that the Commission withhold "final approval" of the Generation Exchange until Duquesne has submitted definitive agreements governing the transaction. OCA Comm. at 6-7; DII Comm. at 12.

Duquesne is not requesting any such final approval at this time. Rather, Duquesne is requesting (i) a finding that the material terms of the exchange, as set forth in the Agreement in Principle, dated October 14, 1998, are in the public interest, and (ii) authorization to proceed with an auction of the FirstEnergy fossil plants to be received in the swap, *provided that* Duquesne submits the final agreements with

² (...continued)
the competitive transition charge." *Id.* § 2802(18).

FirstEnergy (and the winning bidders) for comment by the parties and final approval by the Commission as to any matter within its jurisdiction.

B. Nuclear Decommissioning

The OCA states that "the agreement [in principle] is unclear as to . . . whether Duquesne has established a firm cap on its nuclear decommissioning liability" but that, if such a cap has been established, it provides "some additional, although unquantifiable, value in this transaction for both itself and its ratepayers." OCA Comm. at 11, 4. Duquesne wishes to clarify that it has established a "firm cap" on its nuclear decommissioning liability equal to the amounts already funded and those additional amounts authorized by the PaPUC in the Restructuring Order. Agreement in Principle § 5. The only implementation detail remaining is to develop a method by which such funding amounts can be transferred to FirstEnergy in a manner that preserves the tax advantaged treatment that such funds would have enjoyed if retained by Duquesne. *Id.*³

³ The OTS is mistaken in asserting that the firm cap on Duquesne's nuclear decommissioning liability, as well as the transfer of any responsibility for spent nuclear fuel to FirstEnergy, "was not set forth in the . . . asset exchange agreement." OTS Comm. at 8. The Agreement in Principle states that Duquesne's nuclear decommissioning obligation will be capped "at the total funding amounts allowed by the PaPUC in the DLC restructuring order" and that "[a]ny additional decommissioning costs, or costs associated with spent nuclear fuel or the disposal or decommissioning of any other nuclear equipment, facilities or properties of any kind, will be the sole responsibility of (continued...)

C. Labor Issues

The IBEW states that "if [the Beaver Valley] units are transferred without an acceptable plan for the people who work at those plants, there is a very real risk that the plants could not be operated in a safe and reliable manner. . . . If [Duquesne] doesn't honor [the successorship provision in the CBA], then the safety and reliability of Beaver Valley's operations will be called into question." IBEW Comm. at 6. This issue is outside the scope of the Commission's jurisdiction. The "safety" of operations at Beaver Valley is a matter solely within the jurisdiction of the Nuclear Regulatory Commission, as even the IBEW seems to concede. *Pacific Gas & Electric Co. v. State Energy Resources Conserv'n & Dev. Comm'n*, 461 U.S. 190 (1983); IBEW Comm. at 6 ("There is an extensive [NRC] licensing processing for operators to become qualified to work at a different nuclear unit"). Consequently, the NRC will make a determination of whether the plant is adequately staffed to maintain safety and reliability *before* authorizing Duquesne to transfer operating control to FirstEnergy.⁴

³ (...continued)
FE." Agreement in Principle § 5.

⁴ In addition, as indicated *supra*, the IBEW does not even contend that this Commission should resolve labor issues affecting Beaver Valley. IBEW Comm. at 10; IBEW Supp. Comm. at 4.

D. Administrative Comparisons of Market Value

On October 29, 1998, Duquesne submitted a comparative market value analysis showing that the FirstEnergy plants have a higher value, on a discounted cash flow basis, than the plants being transferred from Duquesne to FirstEnergy. This comparison was performed using the market prices approved by the Commission in the Duquesne and Penn Power restructuring cases.⁵ The OTS suggests that "further detail may be required" to support such a comparative analysis, but does not specify what additional information may be necessary. OTS Comm. at 4.

While Duquesne is willing to continue responding to reasonable requests for further information, we caution the Commission against undertaking an exhaustive analysis of whether the market values of the plants being exchanged are equivalent on an administrative basis. Such an analysis is not necessary, as the purpose of this proceeding is not to make an administrative determination of stranded

⁵ The OCA states that, if "market prices from the Penn Power case" are used to value the Duquesne plants, such plants "might have greater operating value than the assets [Duquesne] would receive from FirstEnergy." OCA Comm. at 8. Duquesne would object to any such analysis as a classic apples-to-oranges comparison. The correct comparison is the value of Duquesne's plants under the market prices approved by the Commission in Duquesne's restructuring case to the value of the FirstEnergy plants under the market prices approved by the Commission in Penn Power's restructuring case.

costs. Rather, the purpose is to establish market values *through an auction* and there is *no dispute* that the generation swap will enhance the value that Duquesne can receive *in the auction*. Furthermore, the Commission and ratepayers have the additional protection of the financial guarantee provided by FirstEnergy. As stated by the OCA, this guarantee is an "extremely important assurance in an infant marketplace for generating assets." OCA Comm. at 10.

E. Transmission Facilities

The Agreement in Principle provides that Duquesne will sell to FirstEnergy certain transmission facilities associated with the Beaver Valley and Mansfield plants as necessary or appropriate for FirstEnergy to deliver the power from those facilities to its customers and to satisfy NRC concerns regarding reliability at the Beaver Valley plant. The IBEW states that "Duquesne has not presented any analysis of the effect on its system of transferring these transmission facilities to FirstEnergy," such as "whether the transfer of such facilities would have an effect on the safety and reliability of Duquesne's electric system." IBEW Comm. at 8. The IBEW's concerns are misplaced. First, the transmission facilities at issue are not being taken out of service; rather, the facilities will continue to be needed to deliver the output of Beaver Valley and Duquesne is merely transferring *ownership* of them to a qualified operator, FirstEnergy, and indeed is doing so in part to *satisfy* NRC reliability concerns. Second, Duquesne and FirstEnergy will continue to coordinate

the operation of their interconnected systems, as they have for years, in a manner necessary to maintain reliability. There will thus be no change in the reliability of the Duquesne electric system. Third, the transfer of ownership of transmission facilities to FirstEnergy will be subject to FERC approval and any concerns the IBEW may have at that time can be raised at FERC.

F. HSS Comments

In typical form, HSS avoids providing any constructive comments, instead characterizing the Generation Exchange as a "belated, sketchy, still-evolving and potentially detrimental proposal." HSS Comm. at 2. Yet, despite this, HSS *does not oppose* the Generation Exchange; rather, it contends only that "final approval" be withheld until the definitive agreements are reviewed and due diligence is conducted. HSS Comm. at 9. As indicated *supra*, however, Duquesne is not requesting any such final approval at this time.

HSS nevertheless plunges forward with various assertions to support its contention that the exchange is "potentially detrimental." These contentions are, at a minimum, ironic when compared to HSS's own testimony in this case. HSS, through the testimony of Dr. Weisenmiller, advocated divestiture as the best method to "extract value from the utility's assets" (HSS Statement No. 1 at 142) and this value, in his view, could be extracted *only* by giving purchasers in an auction "the potential for unit repowering, refurbishment or enhanced efficiency or cost reduction

potential through the buyer's particular strengths (e.g., fuel supply expertise, operations expertise, power marketing expertise)." *Id.* Yet, these sources of value, of course, are *unavailable without the Generation Exchange*. Duquesne does not operate any of the CAPCO fossil plants and thus has no control over fuel supply decisions or non-fuel operation and maintenance expense, nor can it make unilateral decisions regarding repowering or the addition of new plants at the existing sites. HSS is thus simply wrong to assert that the benefits of the Generation Exchange are "purely theoretical" (HSS Comm. at 5); they are *the same* benefits as those identified by Dr. Weisenmiller and, more recently, every investment banker interviewed by Duquesne, all of which supported the Generation Exchange.⁶

HSS also contends that "Duquesne's plants are clearly of a later vintage than FirstEnergy's plants" and that "only one unit that will be acquired by Duquesne, *i.e.*, a unit at the Avon plant, is supplied from a super critical coal fired steam generator, while all of Duquesne's fossil plants utilize that technology." HSS Comm. at 8. HSS is seeking to confuse, rather than inform, the Commission. This "one" super critical coal-fired generator is *600 MW*; this compares to the *770 MW* of

⁶ HSS asserts, relying on excerpts of documents obtained in discovery, that the investment banking firm of CS FirstBoston "saw substantial value [in the CAPCO plants] that Duquesne now proposes to give away for older plants." HSS Comm. at 9. This is hardly a fair statement, given that CS FirstBoston is one of the investment banking firms interviewed by Duquesne that strongly supported the Generation Exchange as value maximizing.

similar generation being transferred to FirstEnergy. Moreover, this "one" generator conveys full operating control, whereas Duquesne's CAPCO fossil assets do not.

In short, even using HSS's method of comparison, Duquesne is exchanging (i) 770 MW of baseload coal-fired capacity that it does not operate for 600 MW of baseload coal-fired capacity *over which the winning bidder will have full operating control*, and (ii) 660 MW of *nuclear* generation for 700 MW of other *coal-fired* generation. As the OCA recognizes, there is no question that the Generation Exchange will maximize value in the Auction.

II. AUCTION PROTOCOLS

Section II of the Auction Plan sets forth the protocols by which Duquesne will auction its generating assets. As indicated in Section II, "Duquesne will use the same two-phase, sealed bid procedure that has been used in virtually all of the other recent generating plant divestitures" (Auction Plan at 6) and these protocols are "designed, to the maximum extent practicable, to allow potential purchasers (*i.e.*, the market) to determine the divestiture structure that best maximizes the value of Duquesne's assets." *Id.* at 10. No party has objected to these protocols and, indeed, the OCA states that it "agrees with the Company that to the extent the Commission finds Duquesne's auction procedures and protocols to be reasonable at this time, the Commission should not conduct a *post-hoc* review of those procedures and protocols." OCA Comm. at 34.

HSS, however, criticizes Duquesne for seeking "*carte blanche* to divest jurisdictional assets" and contends that "there is a critical need for such a [*post-hoc*] review" (HSS Comm. at 2) because, without such a review, "Duquesne has no incentive" to "capture the maximum market values." HSS Comm. at 1, 4; *see also* Environ. Comm. at 6-7. The position of HSS should be rejected. First, Duquesne is not seeking "*carte blanche*" in conducting the auction; rather, Duquesne has requested approval of specific, well-accepted auction protocols (Auction Plan at 6-15) and stated that it will "keep the Commission staff apprised of material developments during the pendency of the auction." *Id.* at 5. HSS, having not objected to any of these protocols, has no basis to argue that they cannot be approved at this time.⁷

Moreover, it is simply wrong to assert that Duquesne has no incentive to "capture maximum market values." HSS Comm. at 4; Environ. Comm. at 7. First, the auction in no way detracts from Duquesne's preexisting incentive to lower its costs or increase its net revenue to mitigate stranded costs to the greatest extent practicable. Duquesne has done so historically through a range of initiatives, including the successful *divestiture* of its interest in the Fort Martin plant.

⁷ It is perhaps not surprising that HSS has not criticized these protocols, as they are the same as those used in the successful auctions that HSS cited in support of its proposal that Duquesne divest its generation. HSS Stat. No. 1 at 141-149.

Second, the fact that the auction proceeds will be used to reduce stranded costs, and thereby will not be flowed through to shareholders, does not lessen this incentive. The point remains that Duquesne will can earn a higher return on the cash proceeds from the auction than it can on the CTC established at the Commission-approved rate of return. Therefore, every dollar of auction proceeds is valuable to Duquesne for its investment potential. Finally, Duquesne will have the incentive to maximize value because higher auction proceeds will shorten the transition period. This, in turn, will release Duquesne from its obligation to provide power at capped rates, thereby eliminating this regulatory burden on Duquesne.

The Commission should therefore approve the auction protocols as reasonable and in the public interest.

III. PROVIDER OF LAST RESORT

The OCA generally supports Duquesne's proposal to explore the sale of the POLR service, stating "the Company should continue to pursue this option as a means of meeting its POLR obligation." OCA Comm. at 16. Enron also expresses support, stating that such an auction "is an excellent first step by Duquesne in addressing the Provider of Last Resort issue." Enron Comm. at 3. Both parties, however, express reservations regarding the *nature* of the POLR service being auctioned, with each apparently preferring an auction that is similar to those ap-

proved in the settlements with General Public Utilities ("GPU") and other Pennsylvania utilities. OCA Comm. at 16-17; Enron Comm. at 4.

Duquesne will not agree to follow these *settlements*. First, the POLR auctions contemplated in those settlements will not produce sale proceeds that can be used to reduce stranded costs. At best, they will produce prices below the shopping credits that provide a temporary price reduction only to those customers not inclined to shop for power.⁸ By contrast, Duquesne's proposal could result in lower stranded costs and a reduced transition period, both of which benefit *all* customers, not simply those not otherwise inclined to shop for power. This is consistent with the Commission's finding "reject[ing] the OCA's Immediate Rate Reduction Proposal consistent with the ALJ's recommendation" (Restructuring Order at 185), which held that:

Because the OCA's proposal for immediate rate reductions entails extension of the transition period, I urge the Commission to reject it. . . . In order to assure ratepayers the transition period will end as quickly as possible, I recommend, *supra*, the immediate divestiture of

⁸ Even then, non-shopping customers may experience different rates depending on whether they are randomly assigned to the host utility or a competitive supplier. Under the settlement proposals, two identical customers with identical consumption remaining on default service could incur different generation charges. Duquesne's proposal avoids this cost-shifting among shopping and non-shopping customers, and among default customers remaining with the utility and those that are assigned to a CDS. In Duquesne's proposal the reduction in the CTC revenue requirement will be allocated to each rate class according to the Commission-approved production cost allocators. This ensures that there is no cost-shifting consistent with the legislation and the Commission's Order.

Duquesne's generating assets as the Company proposes in the event the merger is not consummated.

Recommended Decision at 447. It is thus apparent that Duquesne's POLR auction satisfies a principal objective of the divestiture – *i.e.*, to end the transition period as quickly as possible – as found by Judge Corbett and affirmed by the Commission.⁹

Second, the settlements are inappropriate under the circumstances here because they contemplate auctioning only a *portion* of the POLR service and, even then, only for a *short-term* period (*e.g.*, annual auctions) of time. Because of this, each proposal leaves the electric distribution company with a residual POLR obligation either for that portion of the service that is not auctioned or, worse yet, for the entire POLR load if the auction is unsuccessful. To be sure, these utilities may have been willing to assume this risk in consideration for the benefits associated with their overall restructuring settlement. They also may have believed they had sufficient protection from retained generation to hedge this risk.¹⁰ Whatever the case, neither consideration applies to Duquesne following the auction and that is why

⁹ In addition, the OCA's "rate cut" proposal will simply *encourage* customers already not inclined to shop to remain on POLR service. By contrast, Duquesne's POLR proposal maintains the incentive, embodied in the Commission's Restructuring Order, for customers to receive rate savings only if they shop for power. This will encourage customer switching, one of the Commission's stated objectives.

¹⁰ We note that even GPU will possess more than 1000 MWs of non-utility generation capacity.

Duquesne has proposed to auction *all* of the POLR service for the *entire* transition period.

Third, Duquesne's proposal is easier to implement than the structures envisioned by the settlements. These plans require the Commission to conduct an annual review of the CDS process, approve a petition transferring POLR responsibility to an alternative POLR, review a random customer selection process, develop CDS creditworthiness standards and bond requirements, unbundle Chapter 56 billing and other collection costs, and oversee a new CDS bid cycle each year. Enron Comm. at 36-39. By contrast, Duquesne intends to auction 100 percent of the POLR supply service for the entire rate cap period without a multi-year phase-in. This eliminates the need to conduct an auction each year, to perform an annual Commission review process, and to resolve how customers are selected to receive the benefits of the Competitive Default Supplier services. Duquesne also will retain its POLR obligation and abide by the mandated price cap on generation throughout the CTC recovery period for each rate class. This eliminates the need for the Commission to approve a petition transferring POLR responsibility and eliminates the need for the Commission to develop CDS creditworthiness standards and bond requirements. Finally, as the POLR provider, Duquesne will also perform required customer care functions and provide metering and billing services, as well as assume the customer collection risk. This eliminates the need to unbundle Chapter 56 billing and other

collection costs in the POLR auction process and maintains the necessary customer protections. These features of the Duquesne plan make it easier to implement and will allow the Company to market POLR service in a timely manner in order to maximize value in the auction process.

In sum, Duquesne urges the Commission to permit it to auction the POLR service as proposed, provided that the Commission reserves authority to review and approve any final arrangement as to matters within the Commission's jurisdiction.¹¹

IV. ACCOUNTING FOR AUCTION PROCEEDS

A. Timing of Approval of Auction Accounting

The OCA states that it [but] does not believe it is necessary or appropriate at this time to determine accounting protocols or ratemaking treatment with the type of specificity shown in Appendix G." OCA Comm. at 27. According to the OCA, "the auction itself will not be impacted by the accounting protocols or rate treatment afforded the Company" because "asset bidders will not be concerned with the accounting protocols." *Id.* DII advances a similar position. DII Comm. at 9.

¹¹ Duquesne wishes to caution the Commission and the parties that, if material changes to the POLR proposal are adopted that are adverse to Duquesne (*e.g.*, adopting Enron's position), Duquesne will reconsider and may withdraw its *voluntary offer to auction the POLR service*.

To be sure, "asset bidders will not be concerned with the accounting protocols," but this statement avoids the real issue. The issue is whether, consistent with the Restructuring Order, Duquesne has sufficient certainty that it will recover its *actual stranded costs for Duquesne to commit to binding contractual terms with the winning bidder(s)*. If not, there will be increased uncertainty regarding whether the auction will close and this uncertainty, as discussed *supra*, will harm the auction.

In addition, uncertainty as to the accounting protocols could have other adverse effects. For example, the OCA contemplates an accounting proceeding in which the Commission, on an after-the-fact basis, would permit recovery of only those capital additions that were "reasonable" and "were actually completed prior to closing" of the auction. OCA Comm. at 28, 32. This standard would subject Duquesne to second-guessing and may cause Duquesne not to undertake investments that would otherwise increase the value of the plants. As another example, uncertainty as to the assumed level of amortization of CTC (or net book value, using the OCA's approach) could affect Duquesne's behavior during the auction. In the most extreme case, *if* the issue was not resolved, and Duquesne was concerned that the Commission would adopt an amortization schedule that Duquesne could not meet given the level of expected market prices between January 1999 and the close of the

auction, this could cause Duquesne to withdraw its offer to sell power at 2.6¢/kWh to "jump start" competition.

Duquesne therefore believes it is important to all parties, including customer representatives and labor, to provide Duquesne a reasonable level of certainty regarding accounting protocols before the auction progresses much further. Duquesne recognizes, however, that some parties may not fully understand the detailed protocols set forth in Appendix G or may prefer an approach that differs conceptually from Appendix G but that nevertheless treats Duquesne fairly. In recognition of this, Duquesne proposes to arrange another technical conference that would focus solely on auction accounting protocols. Duquesne will contact the active parties that have expressed an interest in this issue (*e.g.*, OCA, DII, OTS, and HSS) to arrange a mutually agreeable time for such a meeting. Duquesne expects that, through this process, a mutually agreeable plan could be achieved by the end of the year. Duquesne would then file a report with the Commission describing any agreements that have been reached. If no agreements are possible, Duquesne will present its own proposal (whether the same or modified from that contained in Appendix G) for comment by the parties and Commission review and approval.

To facilitate such a technical conference, Duquesne is attaching as Appendix B, a description of three alternative methodologies that, if implemented properly, would each ensure that net proceeds from the auction are accounted for in a

manner that ensures Duquesne will recover its actual stranded costs, no more and no less. The first methodology is the same as described in Appendix G to the Auction Plan ("Method A").¹² The second methodology discounts the market value produced by the auction to January 1, 1999 and applies that value against the stranded costs already determined by the Commission as of January 1, 1999 in the Restructuring Order ("Method B"). This method should eliminate many of the concerns/disputes associated with Appendix G because it uses Commission-approved determinations of net book value and stranded costs as of January 1, 1999 and discounts the net proceeds from the auction using the Commission-approved discount rate.¹³

The third methodology is similar in concept to that suggested by the OCA, *i.e.*, that a final accounting could be accomplished on the date of closing of the auction using actual information regarding book values and market values as of that date. To facilitate discussions with the OCA and other parties, Duquesne has attempted to describe the factors that would have to be considered and addressed in the use of any such methodology ("Method C"). Duquesne cautions the Commission

¹² Included in Appendix B is a revised Appendix G reflecting, in black-lined form, changes to the illustration that implements Method A using updated information regarding, for example, the deletion of the FAS 109 regulatory asset and Beaver Valley lease termination costs.

¹³ Included in Appendix B is a revised Appendix G, in black-lined form, that implements Method B.

that these factors will be difficult to address *on a litigated basis* because they involve considerations not addressed in the current record and thus would require further litigation regarding market prices, capital additions, fuel costs, etc. For this reason, Duquesne strongly opposes the use of this method *unless* it is possible, through a technical conference, for the parties to agree on the necessary implementation details.¹⁴

B. Transaction Costs

Duquesne's Auction Plan requests recovery of all reasonable transaction-related costs, including labor-related expenses, incremental operation and maintenance expense and capital expenditures, expenses related to the Beaver Valley lease, and investment banking, consulting and attorneys fees. Auction Plan, Appendix G at 2-3. Duquesne recently submitted additional information regarding these expenses, including a description of the labor plan for management employees affected by the Auction and the estimated costs of terminating the Beaver Valley lease agreement in the context of the Generation Exchange with FirstEnergy. Letter from J. Moot to J. McNulty, Nov. 5, 1998; Letter from J. Moot to J. McNulty, Oct. 14, 1998.

¹⁴ Because Method C requires information available only at the time of the auction closing, it is not possible, and Duquesne therefore has not, submitted a revised Appendix G implementing Method C using assumptions regarding net auction proceeds, as it has for Methods A and B.

No party has objected to Duquesne recovering the transaction-related costs described in these filings.¹⁵ Moreover, no party objects to providing Duquesne the certainty it needs before making binding commitments to third parties.¹⁶ Without such certainty regarding the recovery of reasonable transaction costs – whether they be related to resolving labor issues, the Beaver Valley lease agreement or making necessary expenditures at the plants being auctioned – Duquesne will be unwilling to take actions that are necessary or appropriate to implementing the auction. Duquesne therefore requests a Commission finding that Duquesne will be permitted to recover the categories of costs described in these filings as an offset to auction proceeds.

¹⁵ The OCA does not oppose recovery of the Beaver Valley lease termination expenses, provided that (i) such expenses are "incremental cost[s] to Duquesne" (*i.e.*, are in addition to the lease expense authorized in the Restructuring Order), and (ii) Duquesne has adequately "explore[d] with FirstEnergy any possible alternatives to termination of this lease." OCA Comm. at 12. Duquesne can represent that (i) the costs are indeed incremental to any amounts authorized in the Restructuring Order, and (ii) that Duquesne exhaustively explored with FirstEnergy every reasonable alternative to terminating the lease, none of which proved viable in the context of the Generation Exchange. A full accounting for the final lease termination costs will be provided at the time a final accounting for stranded costs is made following completion of the auction.

¹⁶ The OCA "recognizes the Company's concern that the Commission should assure that it will be permitted reasonable incurred transaction costs associated with divestiture" (OCA Comm. at 27) and HSS states that "Duquesne and ratepayers need certainty" as to the "categories of costs that Duquesne can deduct from gross proceeds to determine net stranded costs." HSS Comm. at 12.

C. FAS 109 Regulatory Asset

The OCA and DII argue that if the net proceeds from the auction are reconciled on a net of tax basis, Duquesne does not need to recover the FAS 109 Regulatory Asset balance of \$179 million and the associated deferred tax balance of \$57.48 million. OCA Comm. at 33; DII Comm. at 3-4. After considering the comments from these parties during the technical conferences, Duquesne agrees that the FAS 109 Regulatory Asset (and associated deferred tax balance) should be eliminated if Duquesne's proposal to account for auction proceeds on a net of tax basis is accepted.

D. Accounting for Unsold Assets

In proposing the generation auction during the restructuring proceeding, Duquesne's Chief Executive Officer testified that "[t]he auction would set the value of only those assets that were actually sold. For the assets that could not be sold, the absence of any market interest would cap their value at zero." DLC Statement No. 1-R at 17. This aspect of the auction proposal was not opposed by any party and the Commission approved Duquesne's "detailed plan" (Restructuring Order at 82) "to offer [a] divestiture of its generating assets in order to determine the value of its stranded utility generation." *Id.* at 79-80.¹⁷

¹⁷ Duquesne's Auction Plan implemented the approved divestiture proposal,
(continued...)

The OCA and other parties now seem to oppose this aspect of Duquesne's proposal, contending that "any unsold asset should be valued at its administratively determined market value unless Duquesne can demonstrate that a different valuation is appropriate." OCA Comm. at 31. This contention, of course, is barred by the Restructuring Order, which approved Duquesne's divestiture proposal without modification. Moreover, even if the OCA's new-found position was not barred, it is not persuasive. As the Commission held, "only a market-based determination of stranded costs can reasonably satisfy the 'known and measurable' criteria set forth in the Act." Restructuring Order at 83. Under this standard, the OCA cannot have it both ways: a market-based determination for assets having a high value, but an administrative determination for assets that the market deems to have no value. The issue of whether the assets have *great value* or no value is for the market to decide.

Duquesne expects, however, that the "zero value" issue may be mooted by the Generation Exchange. As Duquesne emphasized at the technical conference, the zero value (or "no bid") scenario was expected to occur, if at all, in the auction of Duquesne's nuclear interests in the Beaver Valley and Perry plants.

¹⁷ (...continued)
stating "[t]he sales price shall be deemed to be zero for any Utility Asset for which a transfer is not completed." Appendix G at 1 n.3.

Given that these interests will now support a swap that enables Duquesne to market a portfolio of wholly owned fossil units, it is far less likely that the zero value scenario will occur. Consequently, the Commission may defer resolution of the zero value issue, provided that it approves the Generation Exchange.

E. Deferred Fuel Regulatory Asset

In Docket No. M-00970917, the Commission held that "Duquesne is permitted to create a regulatory asset in an amount equal to its accumulated undercollection of its energy costs incurred during the period commencing February 1, 1996 through the conclusion of its restructuring proceeding." Energy Cost Rate Filing for Duquesne Light Company for Fiscal year Beginning April 1, 1997, No. M-00970917, Order at 3 (Mar. 27, 1997). Consistent with that order, Duquesne's compliance updated its deferred fuel regulatory asset to reflect the balance as of May 29, 1998, the date of "conclusion of [Duquesne's] restructuring proceeding." No party objected to this adjustment in comments on the compliance filing.

The DII and OCA, however, now oppose recovery of this regulatory asset. DII Comm. at 6; OCA Comm. at 31-32. Their position should be rejected for three reasons. First, their position is barred by *res judicata*. The Commission's March 27, 1997 order on Duquesne's ECR filing finally determined that "Duquesne is permitted to create a regulatory asset in an amount equal to its accumulated under collection of its energy costs incurred during the period commencing February 1,

1996 through the conclusion of its restructuring proceeding." Order at 3. It is simply not possible to collaterally attack that order in this case. Second, even if their position was not barred by the March 27, 1997 order, no party, including the OCA or DII, objected to the inclusion of the updated deferred fuel balance in the first compliance filing. These parties therefore waived any right to object to the recovery of such costs now.

Third, Duquesne is perplexed by DII's claim that the Compliance Order "expressly rejected" the updated deferred fuel balance. This claim is based on a quote from the Commission's August 13, 1998 Compliance Order (*see* DII Comm. at 6) *that appears nowhere in that order*. Rather, while the final order rejects the level of the ECR roll-in requested by Duquesne, that is a different issue that has been subsequently appealed to the Commonwealth Court. There is no language whatsoever in the Compliance Order rejecting the updated deferred fuel regulatory asset. This should not be surprising, given that the Commission's auditors have thoroughly audited the books and accounts of Duquesne relating to the deferred fuel regulatory asset and have raised no objections regarding the level of costs recorded. The regulatory asset therefore should be allowed.

V. IMPACTS ON EMPLOYEES AND COMMUNITIES

A. Impacts on Employees

1. Background

Duquesne expects that its employees will be valuable assets to the purchaser(s) of Duquesne's generation portfolio, including FirstEnergy through the Generation Exchange. Duquesne expects that purchasers of Duquesne's generation, including FirstEnergy, will continue to employ a significant portion of the current employee base performing generation-related functions. For those employees that are not retained, however, there are protections in place that will treat these employees fairly. For management employees, Duquesne has offered enhanced severance, early retirement, retraining programs and outplacement services. *See Exhibit A, Letter from J. Moot to J. McNulty, November 5, 1998.* No party has objected to these programs as inadequate.

For Union employees, Duquesne has stated that, absent a new agreement with the Union, its employees will be protected by the existing CBA. The CBA provides for income protection, severance benefits, retraining expenses and an early retirement option. *Letter from J. Moot to J. McNulty at 2 (Nov. 5, 1998).* The current version of this agreement was negotiated during the period when the General Assembly was considering restructuring legislation and thus deregulation of the industry was the subject of discussions during the negotiations in 1996 that resulted

in the current agreement. It is thus not surprising that the 1996 agreement included job security provisions that were extended to 2001 to provide greater certainty to employees during deregulation, nor is it surprising that the agreement specifically addressed the sale of generation as an exception to such job security provisions.

This notwithstanding, Duquesne has sought in good faith to negotiate modifications to the agreement that could avoid any disputes that might arise during implementation of the auction plan. To this end, Duquesne proposed to require that the purchaser(s) of Duquesne's plants assume the CBA, even though the current agreement does not so require.¹⁸ Duquesne also proposed additional enhancements, including a commitment to require buyers to staff the plants with Duquesne employees, select such employees on the basis of seniority and provide those employees with comparable benefits and wages. Exhibit B, Letter of J. Moot to J. McNulty, Sept. 5, 1998. For those employees not selected by the purchaser(s), Duquesne's offer would have provided them certain rights to employment at Duquesne and, for any employees that were terminated because of such "bumping," enhanced benefits, including the continuation of medical coverage for the length of the severance, would

¹⁸ The IBEW disputes this point, but notably it provides no discussion in support of its contention that the purchaser of the plant would be required to assume the CBA. IBEW Supp. Comm. at 4. In any event, the matter is currently before an arbitrator.

be provided. Duquesne also offered an early retirement option as a means of reducing the number of employees that might be involuntarily displaced.

The Union, however, rejected this proposal and therefore Duquesne has indicated that it will proceed with the Auction pursuant to the terms of the CBA.

2. IBEW's Comments

The IBEW's fundamental contention is that Duquesne "has not addressed the effect of its plan on employees or local communities" and therefore the Commission should not permit Duquesne to commence the auction. IBEW Comm. at 5. This argument has no substance. Duquesne will proceed with the auction *pursuant to the CBA* and therefore any "effects" of the auction on Union employees will be precisely those effects that the Union has agreed are reasonable. To be sure, the precise number of employees that will be retained by the auction purchaser(s) is not known *today*, nor is the precise number of employees that will return to other jobs at Duquesne or the precise number of employees that will be severed. But that is because the auction *has not yet commenced*. Until it does, and definitive agreements are entered into with the plant purchasers, including FirstEnergy, the precise effects, in these terms, will not be known. That, however, is not the issue. The issue is *the nature of the protections* for affected employees and those, quite clearly, are known today. Union employees will be protected by the CBA and non-union employees will be protected by Duquesne's management plan. Once the auction has

been completed, including negotiations with FirstEnergy, Duquesne will provide the Commission the required "discussion of the impacts of the [auction] on the utility's employees" (66 Pa.C.S. § 2806(e)) in more precise terms, including a quantification of the related transition costs.

No more is required under the Customer Choice Act. Indeed, noticeably absent from the IBEW's comments is any contention that its position – which is predicated upon dire predictions that "hundreds of Duquesne employees [may] lose their jobs" (IBEW Comm. at 10) – is supported by the Act. The Act, by contrast, expressly contemplates that there will be job losses and provides only that these impacts be discussed with the employees, described to the Commission and that any transition costs be recovered:

There are certain changes to a utility which will create transition costs to accomplish the move to a competitive market. These changes may entail the closure of facilities or *reduction in employee levels*. If such actions are to be undertaken, the utility must fully inform the commission of the impact of such decisions on local communities and on social services and of any tax implications of the auctions. The utility is expected to *discuss the transition to competition with its employees* or their certified representatives and *may provide severance, retraining, early retirement and outplacement services*. Such transition costs may be recoverable under the competitive transition charge in Section 2808 (relating to competitive transition charge).

66 Pa.C.S. § 2802(18) (emphasis added). There is thus no statutory basis to prohibit Duquesne from commencing the auction until all "effects" on employees have been identified, when those effects can only be known in their entirety at the conclusion of

the auction. Rather, the Act contemplates the very process being followed by Duquesne and, given that Duquesne is proceeding pursuant to the CBA, the Union can have no legitimate objection to Duquesne commencing the auction.

Finally, and equally important, the IBEW fails to recognize that the auction is the *best* method for providing security to Duquesne's generation-related employees. As Duquesne testified in the restructuring proceeding, "[a]s a stand alone company, Duquesne is simply too small to remain the generation business." DLC Statement 1-R at 17. By contrast, purchaser(s) in the auction will be larger, more efficient companies committed to remaining in the generation business on a long-term basis. Because of this, they will be more likely than Duquesne to (i) operate the plants at competitive levels, (ii) extend the lives of the plants by repowering and (iii) construct new generation capacity at the existing sites if market conditions permit. All of these benefits could extend the terms of employment for the workforce at these plants beyond the time they could expect to have employment with Duquesne. Moreover, as part of a larger generation company, Duquesne's employees will have more room for advancement and long-term development.

By contrast, Duquesne, as a stand-alone company, could not offer these prospects to the same degree. Duquesne does not have a sufficient generation *portfolio to achieve generation synergies on a scale that would be competitive in the industry*. Duquesne's generation therefore would tend to be less competitive than it

otherwise would be and, as a result, be more vulnerable to a shutdown than if the generation were operated by a large scale generation company. Furthermore, as a *company not committed to remaining in the generation business, there is no reason to expect Duquesne to commit the funds necessary for new construction at any of its existing plant sites. Finally, given the economics of Duquesne's nuclear generation, it is possible that, as a stand-alone company, a decision could be made to shut down the Beaver Valley plant, which employs the majority of Duquesne's plant-related workforce. By contrast, the Generation Exchange with FirstEnergy will place the plant in the hands of an experienced nuclear operator that is committed to remaining in the nuclear generation business and that has a sufficient scale of nuclear operations to foster the long-term, efficient operation of Beaver Valley.*

For all the foregoing reasons, the objections of the IBEW, and its requests for delay, should be rejected.

B. Impact on Communities

The IBEW also contends that "it is simply not possible to tell how the local communities in the greater Pittsburgh area will be affected by Duquesne's plans. . . . Among the issues . . . are tax revenues, safety (particularly regarding the proposed transfer of Beaver Valley), and the effect on communities if numerous Duquesne employees lose their jobs." IBEW Comm. at 10. The IBEW's comments are misplaced as to each category of "effects on communities." First, as to the effect

on "tax revenues," the Commission is not a taxing authority and has no jurisdiction to consider or alter any effects on "tax revenues." *If* there indeed are local or state tax authorities that will be impacted by the auction, they can raise and address their concerns in any manner provided for by law. (We note that, as of this date, no such tax authority has intervened in the case.) Furthermore, it is not even possible, at this early stage, to assess any such tax impacts, given that no valuation has yet been placed on the plants and related real property by the purchasers. The issue is simply a red herring raised to delay the auction.

Second, the effect on "safety" at Beaver Valley is, as indicated *supra*, a matter not within the jurisdiction of the Commission. It is an issue that will be considered by the Nuclear Regulatory Commission in the context of its review of the transfer of authority to operate Beaver Valley to FirstEnergy.

Third, the impact of "job losses" on communities is, for the reasons discussed *supra*, a misplaced concern. The auction is the best method for ensuring the long-term employment and growth of a generation-related workforce at the plants currently owned by Duquesne. Whether at Beaver Valley or the other plants, the new purchasers will be entities that are committed to remaining in the generation business and therefore will be more able than Duquesne to provide long-term employment in generation-related functions. In addition, to the extent there are workforce reductions, employees will be protected by the severance benefits,

retraining programs and outplacement services agreed to by the Union in the CBA and, for management employees, in the plan submitted by Duquesne on November 5, 1998.

VI. OTHER ISSUES

A. Asset Bundles

The OCA argues that Duquesne should be prohibited from bundling with its generation portfolio the sale of (i) the non-rate base units at Phillips and Brunot Island, and (ii) the contract for the sale of 100 MW of firm power (referred to as the power sale agreement or "PSA"). The OCA argues that this is appropriate because (i) as to Phillips and BI, it would otherwise be "difficult to determine the exact value of each plant" and (ii) as to the PSA, the contract was entered into "through [Duquesne's] own initiative" and was "never approved by the Commission." OCA Comm. at 24.

Duquesne strongly objects to the OCA's recommendation. With respect to the Phillips and Brunot Island facilities not in rate base, the OCA's proposal will harm ratepayers because it will would require Duquesne to auction separately the rate base and non-rate base units *of the same plant* – Brunot Island. The result of any such bifurcation could be two owners of the same plant, with the necessity of these entities entering into joint ownership agreements regarding the use of shared facilities and property supporting the operations at Brunot Island. Neither

purchaser would therefore have full control over the plant and, because of this possibility, it is reasonable to expect bidders to discount their bids for Brunot Island. Somewhat ironically, this is the same adverse result that Duquesne *avoided* through the Generation Exchange with FirstEnergy and, as the OCA concedes in that context, a consolidation of control over plants "is critical to Duquesne's maximization of market value in the context of the auction."¹⁹

The OCA's position on the bundling of the PSA also should be rejected. The PSA was auctioned as an integral component of Duquesne's retail access pilot program. During the course of that proceeding, the Commission encouraged all Pennsylvania utilities to "sell an amount of capacity into the market equivalent to the pilot amount." *Chapter 28 Electricity Generation Customer Choice and Competition Act Retail Access Pilot Programs*, Docket Nos. P-00971168, *et al.*, slip op. at 3 (Oct. 2, 1999). Duquesne's 100 MW sale complied with that order and was reported to the Commission to demonstrate compliance with the October 2, 1998 order.

It is unpersuasive for the OCA now to contend that the Commission "never approved" the PSA. OCA Comm. at 24 & n.7. Duquesne's power sale

¹⁹ OCA Comm. at 8 (the substitution of partial, minority ownership interest in the plants that Duquesne is transferring to FirstEnergy with an undivided interest in the plants that FirstEnergy is transferring to Duquesne is critical to Duquesne's maximization of market value in the context of the auction").

auction clearly was pro-competitive and the fact that Duquesne auctioned the PSA *prior* to the time the Commission *ordered* every other utility to make power available hardly provides a basis for penalizing Duquesne in the auction. The simple fact remains that Duquesne's PSA was in compliance with an order of this Commission and that, because of another order of this Commission (the Restructuring Order), Duquesne no longer possess generating facilities to support the sale.²⁰ The Commission should therefore approve bundling the PSA with the sale of Duquesne's generating assets.²¹

If, however, the Commission accepts the recommendation of the OCA (which we strongly oppose), Duquesne hereby offers, to avoid a dispute that could harm or delay the Auction, the following alternative proposal. Duquesne would

²⁰ An auction of the PSA would not have been required if the Commission had accepted Duquesne's proposal to auction its generation at *the end* of the transition period. The Commission, however, rejected that proposal and accepted instead Duquesne's alternative proposal that the generation be auctioned immediately.

²¹ Duquesne also notes that OCA's position regarding the PSA is inconsistent with its position on Duquesne's offer to sell the POLR service and use the proceeds to reduce stranded costs. With respect to that offer, the OCA has stated that "the POLR service may be valuable and competitive bidders may be willing to pay a per-customer fee to obtain such customers Such fees could then be used to reduce stranded costs." OCA Comm. at 18. The OCA should not be permitted to have it both ways simply because it perceives the PSA as having less (or negative) value than the POLR service. Duquesne also reserves the right to bundle the PSA with the POLR service if Duquesne's other proposals are not accepted.

agree to flow through to ratepayers all the net proceeds from the sale of both the rate base *and* non-rate base portions of Phillips and Brunot Island if the Commission permits Duquesne to bundle the PSA and the non-rate base portions of the Phillips and Brunot Island plants in the auction. This alternative will clearly benefit ratepayers in two respects that could not be achieved without this offer. First, it will allow Duquesne to auction Brunot Island as a stand alone plant, as opposed to auctioning pieces of it, which is "critical to Duquesne's maximization of market value in the context of a generation auction." OCA Comm. at 8. It therefore will maximize the value of the *entire* plant, thereby mitigating stranded cost recovery for the rate base portions of it. Second, the offer will allow ratepayers to reap the benefits of the sale of the non-rate base portions of Brunot Island, which are no longer entirely cold-reserved. In response to market conditions in the Summer of 1998, Duquesne reactivated 65 MW of capacity at the non-rate base portion of Brunot Island. This operable capacity may prove valuable in the market, particularly if it is included in the sale of the entire Brunot Island plant.

Duquesne therefore requests that the Commission reject the comments of the OCA regarding Phillips/Brunot Island and the PSA or, in the alternative, that it accept Duquesne's alternative proposal, as described above.

B. Reliability Issues

1. Must Run Contracts

(a) Response to OCA

The OCA states that, while it "agrees with Duquesne that reliability is critical and must be maintained," it is nevertheless "concerned" that the proposed must run agreements "could nonetheless have an adverse impact on the value placed on these units." OCA Comm. at 26. It suggests that Duquesne should "continue to pursue the most cost-effective and reliable solutions to this problem in a timely manner." OCA Comm. at 26. Duquesne agrees that it should pursue the most cost-effective solutions to must-run issues and will, during the course of the auction, continue to evaluate whether transmission or distribution investments are a more economical means to addressing the local area reliability issues than a must-run agreement (or whether some combination of the two is economic).

At present, Duquesne has identified one potential solution that could reduce reliance on must-run agreements. Duquesne believes that installing capacitors on the transmission and distribution system would allow it to relieve the Cheswick facility from any must-run requirements. In addition, it would reduce the need to call on Elrama to approximately 125 hours per year, depending on system conditions. Duquesne believes that this solution would cost approximately \$10 million. Duquesne requests guidance from the Commission as to whether, *if* this

potential solution would eliminate the must run requirement for Cheswick and significantly reduce the requirements on Elrama and could be accomplished for approximately \$10 million, the Commission would authorize this cost to be deducted from auction proceeds as a transaction cost.

(b) Response to OTS

The OTS states that "there should be limitations on [must run] costs (such as a "rule of reasonableness") written into the operation agreements to protect ratepayers." OTS Comm. at 6. Duquesne agrees that the must-run costs should be reasonable and, indeed, the term sheet set forth in Appendix E permits the generator to charge for service only in the hours it is called on (and, even then, only if its costs exceed market rates), rather than a fixed capacity payment that would be payable by Duquesne and its ratepayers without regard to the number of hours the unit was needed for reliability purposes. In any event, the Must Run Agreement is FERC-jurisdictional and therefore any charges thereunder will be reviewed and approved by the FERC. To the extent that any party has concerns with such charges, it can intervene at the FERC at the time an executed agreement is filed with FERC.

(c) Response to IBEW

The IBEW raises numerous "questions" regarding the must-run agreements and contends that, because not all such questions have been resolved, "Duquesne's proposal . . . cannot be accepted in its current form." IBEW Comm. at

5. Duquesne agrees that not every issue relating to the must-run arrangements has been fully resolved at this time. The point, however, is that these arrangements cannot be finally resolved until the auction commences and Duquesne has negotiated the necessary contracts with the winning bidder(s). At that time, Duquesne will be making a subsequent filing for final approval of the Auction, including those arrangements necessary for maintaining reliability. The IBEW's request for delay therefore should be rejected as another Catch-22 designed to delay the auction.

2. Ancillary Services

In the Auction Plan, Duquesne stated that, following the divestiture of all its generation, it would "arrange for [ancillary] such service[s] on a least-cost basis" and recover the associated costs under a FERC-approved rate (most likely a formula rate to recover such costs as they are incurred). Auction Plan at 29, 31. OCA states that it "is concerned with the imposition of an automatically adjusting formula rate mechanism" and that "all ancillary service charges must be in accordance with [the statutory] rate cap provisions." OCA Comm. at 26-27. Both concerns are premature. At the conclusion of the auction, Duquesne will develop a plan for recovering ancillary service costs and, at that time, any interested parties can comment on the plan when it is filed at the FERC.

C. No Affiliate Bids

The OCA requests confirmation that neither Duquesne nor FirstEnergy (nor any of their affiliates) will be permitted to submit bids in the Auction. OCA Comm. at 22. Duquesne hereby confirms that this is the case, provided, of course, that the Generation Exchange with FirstEnergy is approved. One of the many benefits of the swap is FirstEnergy's commitment not to submit a bid in the Auction.

D. Environmental Liabilities

The OTS states that the allocation of environmental liabilities between Duquesne and the winning bidder (and perhaps FirstEnergy) "needs to be clearly set forth, at this time, so that they may be considered by the Commission in its deliberations on the Auction Plan." OTS Comm. at 7. Duquesne does not understand this request. Duquesne is not requesting recovery of the "cost" of any environmental liabilities it may retain²² under the asset sale or exchange agreements. There is thus nothing for the Commission to "consider" on this issue in its deliberations on the Auction Plan.

²² We have stated that "consistent with recent auctions, the purchaser of generating assets [will] assume[] most environmental liabilities associated with the plant site." OTS Comm. at 7 (quoting DLC Resp. to OTS Data Request).

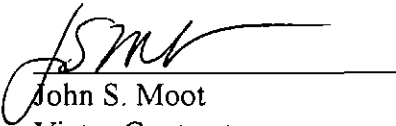
E. Market Power

The OTS states that "Duquesne should be required to perform a market power analysis at the conclusion of the auction and to submit this study to the Commission." OTS Comm. at 10. Duquesne's Auction Plan recognized that the Commission "may consider market power implications in its decision" on the auction. Auction Plan at 12. Duquesne therefore has no objection to providing the Commission with the information necessary to consider market power issues at the time a winning bidder(s) is selected and final approval of the auction is requested.

WHEREFORE, the Commission should approve the Auction Plan consistent with the foregoing reply comments and the form of proposed order attached hereto as Appendix A.

Respectfully submitted,

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Dated: November 23, 1998

APPENDIX A

**FORM OF ORDER
ON DUQUESNE'S GENERATION AUCTION PLAN**

THEREFORE, IT IS ORDERED:

1. Duquesne's Generation Auction Plan is hereby approved consistent with the findings in this Order.
2. The generation exchange with FirstEnergy is in the public interest under the terms set forth in the Agreement in Principle and Duquesne is authorized to proceed with an auction of the FirstEnergy plants it will receive in the exchange.
3. Duquesne shall file the definitive agreements regarding the generation exchange with the Commission for approval of all matters within its jurisdiction.
4. The auction protocols set forth in Section II of the Auction Plan are hereby approved, subject to a requirement that Duquesne provide the Commission with periodic updates on the progress of the auction.
5. Duquesne's proposal to commence an auction of the POLR service is hereby approved, subject to a requirement that Duquesne file with the Commission any agreement to sell the POLR for review and final approval of all matters within its jurisdiction.
6. Duquesne's plan to proceed under the terms of the Collective Bargaining Agreement with the IBEW is hereby approved, subject to a requirement that Duquesne provide a final report on the effect of the Auction on employees and the related transition costs at the conclusion of the auction.
7. Duquesne is directed to convene a technical conference to discuss the protocols for accounting for auction proceeds and to file a report on these discussions within 45 days.

8. Duquesne is authorized to recover, as an offset to auction proceeds, the categories of transaction costs identified in the Auction Plan and supplemental materials.

9. Duquesne is authorized to recover, in the final accounting for stranded costs, a deferred fuel regulatory asset in the amount of \$25 million.

10. Duquesne is authorized to include in the auction the non-rate base units at the Phillips and Brunot Island plants and the 100 MW Power Sale Agreement.

11. Duquesne shall continue to explore the least-cost solution to addressing must-run and other reliability issues associated with the Auction. To the extent that the installation of capacitors reduces must-run requirements in the manner specified in Duquesne's Reply Comments, Duquesne may recover the related costs as transaction costs.

12. Duquesne shall inform all qualified bidders that neither Duquesne nor FirstEnergy, nor any of their affiliates, shall be permitted to submit a bid in the auction.

13. Duquesne shall submit, following selection of the winning bidder(s), information and analyses regarding the effect of the auction on competition in retail electric markets.

APPENDIX B

Alternative Accounting Methodologies

Duquesne filed its Auction Plan on August 27, 1998. The proposed protocols to account for auction proceeds were summarized in Section IX (at 34-36) and detailed in Appendix G. The OCA has raised concerns about the proposed accounting protocols and focused¹ on the proposed adjustments to reconcile timing differences between the date of sale closing and the date of the Commission's administrative determination (January 1, 1999).

The purpose of this Appendix B is to outline three alternative methodologies that, if implemented properly, would ensure that the net proceeds from the auction are accounted for in a manner that ensures Duquesne will recover only its actual stranded costs. First, we will briefly describe the rationale for the "future market value true-up" approach set out in the original Appendix G ("Method A"), and answer some of the main criticisms raised by the OCA. Second, we will describe a simplified alternative ("Method B"), that focuses on the date of the Commission's administrative determination and which, if adopted, should answer the OCA's criticisms. Third, we will attempt to describe what is required to adopt the OCA's concept of a "future book/market" determination of stranded costs ("Method C") and to explain the difficulties of implementing such an approach absent a settlement.

Attached to this Appendix B are two revised versions of Appendix G (for Methods A and B) that present the updated results from the illustrative example contained in the original Appendix G². Method C is described only on a conceptual level and we have not attempted to prescribe a precise accounting protocol susceptible to explication using the example. We note that although the intent of each method is to permit Duquesne to recover only its actual stranded costs, it does not follow that the *ex post* results will be precisely the same. Each method calculates the final stranded cost number somewhat differently, and provides for a different allocation of risks during the interim period after January 1, 1999 and prior to the auction sale closing. Methods A and B provide certainty with regard to how the auction proceeds will be accounted for by the parties. Whereas, in the absence of a settlement, Method C would likely require a potentially contentious after-the-fact proceeding to account for costs and

¹ The OCA and DII have also raised the issue of accounting for the recovery of the FAS 109 Regulatory Asset in the context of an auction sale. As discussed in Duquesne's Reply Comments, there appears to be no further disagreement between Duquesne and the interveners on this issue. Accordingly, the treatment of the FAS 109 Regulatory Asset will be discussed in this Appendix B only insofar as it relates to timing issues under the alternative accounting protocols.

² The revised Appendices reflect the treatment FAS 109 noted above, and have been updated to reflect the swap agreement with First Energy Corporation.

revenues during the interim period.

**Method A
(Original Appendix G Protocol including FAS 109 Reconciliation)**

The original rationale of Appendix G was that the Restructuring Order establishes stranded costs (as adjusted for the loss of merger synergies) at January 1, 1999³. At this date, a regulatory "CTC Asset" with a principal balance of \$1.5 billion⁴ is established on which Duquesne is permitted to earn an 11% pre-tax total return. The principal balance of the CTC Asset includes the \$179.00 million FAS 109 Regulatory Asset. If no auction of generating assets ultimately takes place, this determination of stranded costs is final. During the interim period, prior to closing of any auction sale, interim CTC revenues⁵ are used to amortize this CTC Asset.

The original deferred tax balance⁶ associated with the January 1, 1999 starting balance of the CTC Asset is also amortized during the interim period, although this balance does not earn the 11% return allowed on the CTC Asset. A portion of the interim CTC revenues are allocated to amortization of the deferred tax balance based on the following rule: the amortization of the deferred tax balance is proportionate to the amortization of the CTC Asset. Thus, if 10% of the starting balance of the CTC Asset is amortized during the interim period, an equivalent 10% of the starting balance of the deferred tax balance will be amortized over the same period.

On the date of the auction closing, a Market Value Offset Credit based on a "future market value true-up" can be calculated and applied to reduce the outstanding principal balance on the CTC Asset⁷. In addition, at the date of the auction sale closing, the \$179.00 million FAS 109 Regulatory Asset will be applied as an additional offset credit to the unamortized CTC Asset balance, and the associated \$57.48 million of deferred taxes will be applied as an additional credit to the unamortized deferred tax balance. After application of the above credits, the remaining CTC Asset and deferred tax balances can be recovered through final CTC rates. In order to achieve the average shopping credits originally set out in the Commission's Restructuring Order, the annual CTC revenue requirements are constrained in each year. The final CTC rates will recover the unamortized balances and earn the allowed 11%

³ Restructuring Order, at 83.

⁴ Stand Alone Base Case, Appendix G (at 2a).

⁵ Based on the approved Pilot program credits.

⁶ \$653 million, Stand Alone Base Case, Appendix G (at 2a).

⁷ Similarly, a Deferred Tax Offset Credit is calculated to reduce the unamortized deferred tax balance.

return on the CTC Asset, while satisfying the shopping credit constraints.

The appropriate true-up to calculate the Market Value Offset Credit is between two market values (calculated at different points in time) not between a future market value and a future book value. The two market values must be compared at the same date, and a comparison at the future date (following the auction sale closing) is appropriate because the true-up is being applied against the unamortized CTC Asset and associated deferred tax balances at that date. The timing adjustment proposed by Duquesne to the Commission's January 1, 1999 administrative value of \$110.95 million is to adjust for the projected net margins in OCA's analysis and value those margins at the time of closing. For illustrative purposes, this results in a January 1, 2000 value of \$137.95 million as calculated in Appendix G. The future administrative value reflects both the time value of money and the increase in value due to discounting only post-99 margins in the analysis.

In its Response, the OCA has raised a number of issues that it believes need to be addressed in any Commission approval of an accounting protocol. The protocols of Method A address the underlying economics of the issues raised by the OCA, although perhaps these have not been fully understood:

1. The FEC swap⁸ does not affect the net book value used to calculate stranded costs in the original administrative determination of value at January 1, 1999: The FEC assets only affect the market value received in the auction⁹.
2. Because of the FEC swap, closings of auction sales of Utility Assets (excluding Phillips and the non-rate based portions of Brunot Island) are expected to take place at the same time. However, if the Utility Assets are sold in more than one bundle, and the sales close on different dates¹⁰, the offset credits could be applied on the first closing date and the net proceeds from the second sale discounted back to that date at the Commission's approved¹¹ after-tax discount rate of 7.29%.
3. The final net book values and changes in net book value¹² are not used in the original administrative determination of value at January 1, 1999 or the market value true-up at the date of closing.

⁸ OCA Response at 28.

⁹ The tax consequence of having a swap closing immediately followed by an auction closing are that Duquesne will pay tax on the difference between the tax basis of its current generating assets and the combined market proceeds of all auctioned assets.

¹⁰ OCA Response at 28.

¹¹ Restructuring Order at 192.

¹² OCA Response at 28-29.

4. The amount of CTC revenues paid by ratepayers during the interim period¹³ are fully accounted for by amortizing and allowing a return on the CTC Asset from January 1, 1999.
5. The net margins of the generation assets are adjusted to account for the later valuation date,¹⁴ based on the projections of the OCA adopted by the Commission.
6. The new CTC that must be designed¹⁵ is already prescribed by the target shopping credits established by the Commission. The final amount of stranded costs determined will establish the expected duration of the CTC.
7. The calculation of depreciation and capital cost recovery of generation assets realized through the market price for power¹⁶ during the interim period is not necessary to finally determine stranded costs. Beginning January 1, 1999, the CTC Asset is created and all amortization of the CTC Asset is fully accounted for by allocating the interim CTC revenues between amortization and return.
8. Similarly, a calculation of actual capital additions completed¹⁷ after January 1, 1999 and prior to closing of the auction sale is not necessary to finally determine stranded costs. All *actual* costs (capital additions, O&M and fuel) after January 1, 1999 are not used in the Commission's administrative determination of stranded costs and are not used in the true-up of the future market value to the future administrative value.

A revised Appendix G that implements Method A (including the offset for the FAS 109 Regulatory Asset) is attached hereto. The illustrative auction example produces the same net of tax proceeds at year-end 1999 as in the original Appendix G. The administratively determined CTC Asset balance as of January 1, 1999 is amortized using the Pilot Credit CTC Revenues received in 1999. The Market Value Offset Credit (and the offset for deferred taxes) are applied to reduce the unamortized principal balances. An amortization schedule is then established to recover the remaining balance subject to the Commission's shopping credit targets.

Method B
(Alternative Appendix G Protocol including FAS 109 Reconciliation)

The source of much of the complexity and confusion surrounding the original Appendix G protocols was the attempt to reconcile the Commission's determination of stranded costs at January 1, 1999 with a market determined value for Duquesne's generation at a later

¹³ OCA Response at 29.

¹⁴ OCA Response at 29.

¹⁵ OCA Response at 29.

¹⁶ OCA Response at 30.

¹⁷ OCA Response at 31-32.

date. All of the evidence in the record provided net book values at January 1, 1999 and the OCA's discounted cash flow valuation estimated market values as at January 1, 1999. Hence the Commission's Restructuring Order provided¹⁸:

In the event that Duquesne does not file a Divestiture Plan within 90 days from the date of entry of the final Order in this case, in conformity with the foregoing guidelines, the value of Duquesne's stranded utility generation shall be determined based on the record of this proceeding as described below. The first task in making such a determination is to ascertain the net book value of Duquesne's utility generation as of January 1, 1999. Second, we must ascertain the market value of those assets as of January 1, 1999. The difference between net book value and the market value of assets as of January 1, 1999 is the stranded utility generation amount. We note that the determination is the exact same in the event of divestiture, except that the proceeds of sale shall be used instead of the market valuation adopted herein.

The auction valuation process would be much simplified if the auction closing took place on December 31, 1998, allowing the proceeds of sale to be used instead of OCA's valuation of \$110.95 million. The complexities of Appendix G and the many issues raised by the OCA in its Response are an attempt to grapple with this timing issue. However, a simple solution that answers the OCA's concerns and is fair and equitable to Duquesne and the ratepayers may be possible.

As an alternative to Method A, Duquesne proposes under Method B that the after-tax market value of the auctioned units as determined by the market at the date of closing be discounted back to January 1, 1999. The OCA's January 1, 1999 valuation was the result of discounting future after-tax cash flows projected to be received from the sale of output from Duquesne's generating units at market prices. The discounted value of all the years of future output at projected market prices is only a proxy for the actual market value of the generation assets. The actual market value (as of the date of closing) will be known when the sales of Duquesne's assets are completed. By discounting this value back to January 1, 1999 at the Commission's approved¹⁹ after-tax discount rate of 7.29%, we can determine the market value as of January 1, 1999. Adopting this simplified approach to calculating stranded costs at January 1, 1999 has clear advantages that reduce complexity and increase certainty.

First, projections of future market values are unnecessary. January 1, 1999 is the date of the final market determination of stranded costs, when all adjustments to the administrative determination of stranded costs take place. The present valuing of the actual after-tax market value from the auction sale is simple, even if there is more than one closing date.

¹⁸ Restructuring Order, at 83.

¹⁹ Restructuring Order at 192.

Second, projections of future book values are unnecessary. Changes in net book value of generation after January 1, 1999 (whether through book depreciation, the FEC asset swap or capital additions) are not a factor in the final determination of stranded costs. The record evidence already supports the determination of the net book value of Duquesne's generation as of January 1, 1999.

Third, beginning on January 1, 1999 Duquesne will amortize and earn an 11% annual return on the new CTC Asset, the finally determined amount of stranded costs. Calculation of this amortization will take place after the auction sale closing, and thus the receipt of CTC revenues can be easily allocated between amortization and return.

Fourth, after the closing of the auction sale, the Commission's shopping credit targets will limit the total amount of CTC revenue requirements that may be used to establish CTC rates in each remaining year of the transition period. Based on these annual rates, the unamortized stranded costs will be reconciled each year by allocating the CTC revenues actually received between amortization and return.

As discussed above under Method A, the OCA has raised a number of issues that it believes need to be addressed in any Commission approval of an accounting protocol. The protocols of Method B also address the underlying economics of the issues raised by the OCA, and present a more simplified approach:

1. The FEC swap²⁰ does not affect the net book value used to calculate stranded costs at January 1, 1999. The FEC assets only affect the market value received in the auction²¹.
2. Because of the FEC swap, closings of auction sales of Utility Assets (excluding Phillips and the non-rate based portions of Brunot Island) are expected to take place at the same time. However, if the Utility Assets are sold in more than one bundle, and the sales close on different dates²², the net proceeds from each closing are simply discounted back to January 1, 1999 at Commission approved discount rate of 7.29%.
3. The final net book values and changes in net book value²³ are not used in the final determination of stranded costs at January 1, 1999.

²⁰ OCA Response at 28.

²¹ The tax consequence of having a swap closing immediately followed by an auction closing are that Duquesne will pay tax on the difference between the tax basis of its current generating assets and the combined market proceeds of all auctioned assets.

²² OCA Response at 28.

²³ OCA Response at 28-29.

4. The amount of CTC revenues paid by ratepayers during the interim period²⁴ are fully accounted for by amortizing and allowing a return on the final determination of stranded costs capitalized in the CTC Asset from January 1, 1999.
5. The net margins of the generation assets do not need to be adjusted to account for the later valuation date²⁵. The actual market proceeds are brought back to January 1, 1999 and the administrative determination is adjusted at that date.
6. The new CTC that must be designed²⁶ is already prescribed by the target shopping credits established by the Commission. The final amount of stranded costs determined will establish the expected duration of the CTC.
7. The calculation of depreciation and capital cost recovery of generation assets realized through the market price for power²⁷ during the interim period is not necessary to finally determine stranded costs. Stranded costs are determined finally as of January 1, 1999, and all amortization of the CTC Asset is fully accounted for by allocating the interim CTC revenues between amortization and return.
8. Similarly, a calculation of actual capital additions completed²⁸ after January 1, 1999 and prior to closing of the auction sale is not necessary to finally determine stranded costs. Stranded costs are finally determined as of January 1, 1999 and all *actual* costs (capital additions, O&M and fuel) incurred after that date are moot.

A revised Appendix G that implements this simplified accounting protocol of Method B is attached hereto. The illustrative auction example produces the same net of tax proceeds at year-end 1999 as in the original Appendix G. This amount is present valued to January 1, 1999 and a final determination of stranded costs is made, eliminating the SFAS 109 Regulatory Asset. The CTC Asset balance is then amortized using the Pilot Credit CTC Revenues received in 1999, and an amortization schedule is established to recover the remaining balance subject to the Commission's *shopping credit* targets.

²⁴ OCA Response at 29.

²⁵ OCA Response at 29.

²⁶ OCA Response at 29.

²⁷ OCA Response at 30.

²⁸ OCA Response at 31-32.

**Method C
(Future Book Value Compared to Future Market Value)**

HSS²⁹ argues that the Auction Plan accounting should be easy: simply auction the plants and compare book value to market value at the date of sale. However, as discussed above, this is not the case, as the OCA recognizes, for several reasons. The record in this case establishes an administrative determination of stranded costs at January 1, 1999. Additionally, the Restructuring Order provides for immediate retail access to 2/3 of Duquesne's customers at interim CTC rates based on the credits in the Pilot program. The closing of the asset sale will not occur until late in 1999 at the earliest. A future determination of stranded costs at closing postpones the write down of generating assets on the regulatory books and the establishment of a CTC Asset on which a pre-tax 11% return has been allowed by the Commission. The interim accounting for sales to non-shopping customers, "mitigation" sales at market and interim "CTC" revenues is not trivial, and these timing differences cannot be lightly dismissed in the absence of a settlement.

The OCA recognizes the complexities raised by these timing differences and submits that if the Commission is to approve an accounting and ratemaking proposal for the auction at this time, the proposal must properly account for three factors³⁰:

1. The change in book value between January 1, 1999 and the time of final determination of stranded costs (i.e., the closing of the auction sale).
2. The amount of CTC revenues paid by ratepayers during the interim period prior to the closing of the auction sale.
3. An adjustment to the administrative determination of stranded costs to reflect the actual net proceeds from the auction.

Duquesne agrees with the underlying premise of the OCA's submission (i.e., the best measure of stranded costs of the generation assets at the date of closing is the difference between the asset's true value as determined by the market and the net book value at that date). Indeed, Duquesne's Rebuttal case³¹ proposed an auction to determine stranded costs as of the end of the transition period. The proposal had four key components -- a rate cap, a minimum amortization commitment resulting in fixed book value targets at the end of 2005, a shopping credit equal to the market price of power, and an allowed ROE with a spillover mechanism to protect customers. However, this proposal was attacked as unworkable by the OCA and other interveners who argued that interim calculations of the market price of power and oversight of

²⁹ HSS Response at 10.

³⁰ OCA Response at 28-29.

³¹ Testimony of David D. Marshall, Duquesne Statement 1-R at 12-17..

the ROE mechanisms were invitations to continuing dispute. In Rejoinder³², Duquesne responded to these criticisms by offering the auction proposal that was accepted in the Commission's Restructuring Order and is now the subject of the Auction Plan.

Implementation of the OCA's three factors to make a final future determination of stranded costs based on future book and market values is possible. However, this "Future Book/Future Market" Method C of measuring stranded costs would involve an interim period of rate regulation requiring determinations of market prices to allocate interim CTC revenues, adjustments to the regulatory asset balances, agreements on or determinations of book depreciation, and oversight of capital additions. The determination of final book values would be further complicated by the "Swap Agreement" with First Energy Corporation ("FEC"), as capital additions to generating assets transferred to FEC would not be reflected in the purchase price for the assets ultimately auctioned.

From January 1, 1999 until the auction of its generating assets, Duquesne will receive the generation rate cap for customers who choose not to shop and interim CTC revenues for those who do shop. In addition, Duquesne will receive wholesale revenues from sales of power not needed to serve customers who shop. If stranded cost determination and recovery is delayed to the date of the auction, these revenues must fully fund the generation revenue requirement -- book depreciation of generating assets, amortization of regulatory assets, generating plant operating expenses, capital additions, return on generation and regulatory assets, and income taxes. To ensure the company did not earn too little or too much during this period, in effect the parties would have to conduct a rate case, setting targets not only for book depreciation, but also for the other components of the revenue requirement, including the allowed returns. Even with a settlement on what the proper level of revenue requirement would be to fund a given book depreciation schedule, there is no guarantee that the Company would realize those revenues. The settlement would need to deal with an agreed allocation of risk on this issue, because if the shopping credits and the market price of power were different during the interim period, generation revenues received would be more or less than required to earn the agreed return. Alternatively, a true-up of ending book value or the starting CTC Asset balance would be necessary at the time of the auction sale closing.

³² Testimony of David D. Marshall, Duquesne Statement 1-Rejoinder at 1.

APPENDIX G REVISION -- METHOD A

ACCOUNTING PROTOCOLS
FOR DUQUESNE GENERATION AUCTION

As required by the Commission, the proceeds from the auction conducted pursuant to this Auction Plan will be used to determine the stranded costs of Duquesne for the Company's generation. This section will discuss the accounting protocols necessary to establish a market-based stranded cost valuation for generation from the auction proceeds and to reconcile that actual valuation with the collection of interim CTC charges¹ based on the generation credits from Duquesne's Pilot.

A. Net Auction Proceeds

The net auction proceeds ("Net Auction Proceeds") from the transfer of all divested Utility Assets² shall be defined as the sum of the sales prices paid by

¹ The Commission's August 13, 1998 Opinion and Order on Duquesne's compliance filing (the "Compliance Order") adopted the Company's proposal for the interim CTC charges. Compliance Order at 12.

² Utility Assets do not include assets that have been excluded by the Commission in its determination of stranded costs (*i.e.*, the non-rate base portions of the Brunot Island generating units and the Phillips generating unit). Proceeds from these excluded assets will not be considered for purposes of determining the Net Auction Proceeds. All other generating assets to be auctioned by Duquesne (including the assets exchanged with FirstEnergy Corporation ("FEC")) are included for purposes of determining stranded costs and are considered to be Utility Assets for purposes of the auction. Pursuant to its Agreement in Principle (the "Swap Agreement") to exchange certain generating asset with FEC, as filed with the Commission on October 14, 1998, Duquesne will auction the wholly-owned fossil generating assets received from FEC (the "FEC Assets") rather than the partial interests in
(continued...)

the new owners less the transaction costs.³ Transaction costs shall include all reasonable incremental expenditures that are assignable to the divested Utility Assets ("Transaction Costs"), including but not limited to:

- (i) The costs of developing and implementing this Auction Plan (e.g., fees of outside experts, including investment bankers, engineering and environmental consultants, economic and financial consultants and legal counsel, and any expenditures associated with a potential transfer of the Beaver Valley Unit 2 lease); including the costs of implementing the Swap Agreement with FEC, i.e., the costs of terminating the Beaver Valley II lease so as to permit the transfer of Beaver Valley II to FEC);

² (...continued)

fossil and nuclear generating assets transferred to FEC (the "Transferred Assets"). The sum of the sales prices paid by the new owners for the FEC Assets will be included in the Net Auction Proceeds. The Transferred Assets will not be auctioned and thus not included in the Net Auction Proceeds. However, the book values used in the Commission's administrative determination of stranded costs as of January 1, 1999 will still be used for finally determining stranded costs based on the offset credits to stranded costs and to deferred taxes derived from the market values determined in the auction. In summary, book values are based on Duquesne's original generation assets and market values are based on the generation assets auctioned.

³ The sales price shall be deemed to be zero for any Utility Asset for which a transfer is not completed, whether because no qualifying bids were received or because conditions precedent to such a transfer were not satisfied. In the event Duquesne receives a qualifying "negative bid" (See Section II.D., E. Qualifying Bids) that Duquesne is prepared to accept, the negative bid will be used to reduce the sum of the other non-negative sales prices for Utility Assets in determining the Net Auction Proceeds.

- (ii) Incremental O & M costs (e.g., associated with the demarcation of facilities at Utility Assets), employee costs, environmental costs and any tax implications relating to this Auction Plan other than those described below under After-tax Auction Proceeds;
- (iii) Incremental divestiture-related capital expenditures (e.g., associated with the demarcation of facilities at Utility Assets) necessary to complete the transfers to new owners; and
- (iv) The present value of any severance costs payable to employees at the Utility Assets divested pursuant to this Auction Plan.

As an illustrative example assume that the sum of the sales prices for all Utility Assets is equal to ~~\$500~~ \$590 million and that Transaction Costs total ~~\$25~~ \$115 million, including: \$20 million for fees of outside experts; \$90 million for the termination of the Beaver Valley II lease; \$3 million of incremental O & M, employee and environmental costs; and \$2 ~~of~~ million of incremental divestiture-related capital expenditures. In that event, the Net Auction Proceeds would equal \$475 million or the sum of the sales prices (~~\$500~~\$590 million) less the Transaction Costs (~~\$25~~\$115 million).

B. After-tax Auction Proceeds

The after-tax gains or losses on the transfer of ~~divested~~ the auctioned assets will be reflected in determining the after-tax auction proceeds ("After-tax Auction Proceeds") from the sale of Utility Assets under this Auction Plan. The After-tax Auction Proceeds shall be defined as the Net Auction Proceeds less current taxes payable ("Current Taxes") as a result of the transfers of the Utility Assets divested.

Current Taxes are defined as all Pennsylvania or Ohio, and any other applicable gross receipts, excess dividends, property transfer and sales taxes (including applicable surcharges); plus, the difference between the Net Auction Proceeds and the remaining tax basis⁴ of the Utility Assets divested at the date of transfer, multiplied by the then-current combined federal-state income tax rate (currently 41.4935%).

Again, as an illustrative example, in addition to the above assumptions assume the tax basis of ~~assets~~ Utility Assets divested is \$180 million on the date of closing, the tax rate is 41.4935% on the date of closing and no other Pennsylvania or Ohio taxes are applicable. In that event, the After-tax Auction Proceeds will

⁴ The net tax effect of the implementing the Swap Agreement and auctioning the FEC Assets and Duquesne's remaining interest in Cheswick, Elrama, and the rate-based portion of Brunot Island, is that the tax basis of all auctioned assets will effectively be equal to the tax basis of Duquesne's generating assets as if the Swap Agreement had not been implemented. For purposes of the illustrative example, all references to the "tax basis of Utility Assets" divested are intended to refer to the tax basis of Duquesne's generating assets, including the Transferred Assets, and excluding the FEC Assets.

equal \$352.59 million, or Net Auction Proceeds (\$475.00 million) less Current Taxes (\$122.41 million) as shown in the table below.

	(\$000)
Sum of Sales Prices	500,000 <u>590,000</u>
(Transaction Costs)	(25,000) <u>(115,000)</u>
Net Auction Proceeds	475,000
(Tax Basis)	<u>(180,000)</u>
Taxable Gain	295,000
Current Taxes @ 41.4935%	<u>(122,406)</u>
After-tax Auction Proceeds	352,594

C. Stand Alone Base Case

The Restructuring Order includes a determination of stranded costs based on an administrative determination of the after-tax market value of Duquesne's generating assets as of year-end 1998. This total after-tax value is based on the Commission's acceptance of the OCA's calculation⁵ of a NPV of \$99.4 million from a margin analysis of Duquesne's owned-units as reproduced in Appendix G (at 1a). The OCA proposed certain adjustments to the results of the margin analysis, which were rejected in part and accepted in part by the Commission.⁶ The net effect of all

⁵ Schedule MIK-1, December 1997 Update, Page 2 of 3.

⁶ Restructuring Order at 123, 128.

the Commission's accepted adjustments to the OCA's \$99.4 million margin NPV was to increase this value to \$110.95 million.

The Stand Alone Base Case for Duquesne is attached as Appendix G (at 2a). This table presents a revised Appendix B from the Restructuring Order, with an additional column to show the corrections to the Commission's deferred tax calculation from the Compliance Order.⁷ A copy of the Stranded Cost Allowance from the Compliance Order is reproduced in Appendix G (at 3a).

Three changes are necessary to properly reflect the administrative determination of stranded costs for Duquesne on a stand alone basis. First, the Compliance Order Stranded Cost Allowance in Appendix G (at 3a) includes the generation Merger Savings of \$152.28 million. In a non-merger scenario, no generation merger savings are obtainable. Second, pursuant to the Compliance Order the Deferred Fuel Cost Regulatory Asset should be shown at its updated value of \$25.00 million because Duquesne has been denied a roll-in of its ECR at the higher value reflected in the original compliance filing. Third, the Commission's calculation of \$493 million for deferred taxes is in error, and must be restated as \$653

⁷ The Compliance Order was issued on August 13th and contains certain calculational errors. Duquesne corrected those errors in its revised compliance filing, and a description of the main corrections is summarized here.

million on a stand alone basis, most of which is attributable to the foregone merger synergies. The corrections to the deferred tax calculation are summarized below:

Deferred Tax Item	(\$Million)
a. Generating Plant Book ⁸	372.46
Corrected Value	<u>411.34</u>
a. Increase	38.88
b. Merger Savings	(107.99)
Corrected Value	<u>0.00</u>
b. Increase	107.99
c. Deferred Fuel Costs	4.77
Corrected Value	<u>17.73</u>
c. Increase	12.96
Total Increase (a. + b. + c.)	159.83
PA Jurisdictional (at 99.9%)	159.67

⁸ For purposes of this summary calculation, the Restructuring Order's understatement of deferred tax balances by \$38.88 million has been attributed solely to Generating Plan Book. Duquesne took exception to this computational error in the Merger Compliance Filing. Page 2, note 2 clearly states that "Appendix A [to the Compliance Filing] also provides a description and break-down of the correct deferred tax balance associated with the Commission's administrative determination of stranded costs, while excluding the deferred taxes associated with disallowed cost items, including BI and Phillips. The Final Order does not explain how the deferred tax balance contained in Appendix D was derived, but it is not correct." The relevant pages of Appendix A to the Compliance Filing are reproduced here in Appendix G (at 4a-4c). The difference between the Commission's undocumented \$493.345 million deferred tax balance and Duquesne's detailed calculation of \$532.188 million (Appendix G at 4b) is \$38.88 million, as adjusted for the 99.9% PA jurisdictional factor.

D. Reconciliation with Stand Alone Base Case

To reconcile the stranded costs resulting from the actual market value (i.e., the After-tax Auction Proceeds) with the Stand Alone Base Case resulting from the Commission's year-end 1998 administratively determined value of \$110.95 million will require an adjustment to account for the timing of the auction.⁹ Continuing with the example discussed above, assume the asset sales close at year-end 1999 and the After-tax Auction Proceeds (as calculated above) are \$352.59 million. This amount cannot be reconciled directly (i.e., by subtraction) with the Commission's \$110.95 million administratively determined value because of the timing difference. However, the OCA's margin analysis can be moved forward to year-end 1999 to calculate the comparable present value by applying the OCA's NPV of margin methodology from that date forward.

Appendix G (at 5a) contains a summary table showing the values that would be obtained from Mr. Kahal's margin analysis if the margins were recalculated at the same 6.88% discount rate at year-end 1999 and year-end 2000. This table is based on the workpapers filed with the OCA direct testimony, including a spreadsheet (Margin_2.xls) prepared by OCA witness Kahal. The first column replicates the results of the OCA analysis as filed (at year-end 1998). The second and third

⁹ The Commission recognizes that the divestiture may not be accomplished by January 1, 1999 and requires that the actual stranded utility generation value be reconciled. *See* Restructuring Order at 81-82.

columns show the recalculation of the margin results adjusted for timing. The OCA's after-tax margin NPV increases to \$126.3 million and \$164.5 million at year-end 1999 and 2000 respectively. The difference from the year-end 1998 value of \$99.4 million is shown at the bottom of the table.

The future NPVs are greater than the year-end 1998 value by \$27.0 million and \$65.1 million respectively. These values have been calculated directly from Margin_2.xls. A printout of pages from Margin_2.xls is attached as Appendix G (at 6a-6d), and shows the annual after-tax margin summaries for each Duquesne plant as calculated by Mr. Kahal. The year-end 1998 margin NPVs for each unit appear at the far right of the second page of each table following the year 2026. The calculated OCA values are used by Mr. Kahal to derive the margins shown on Schedule MIK-1, December 1997 Update, Page 2 of 3.

Continuing with the example discussed above, Duquesne will adjust the Stand Alone Base Case administrative value of \$110.95 million upward by the \$27.0 million difference shown in Appendix G (at 5a) ~~and then subtract this adjusted value from.~~¹⁰ Based on the difference between this future administrative value and the After-tax Auction Proceeds ~~to determine the,~~ an offsetting credit to ratepayers

¹⁰ This assumes the closing occurs at year-end 1999. An earlier or later closing would require a different adjustment. The values at year-end 1998, 1999 and 2000 can be used to interpolate the adjustment if the closing of the auction occurs earlier in calendar 1999 or later in calendar year 2000.

(“Market will be applied. The total credit (“Market Value Offset Credit”)-Credit”)
will be calculated by first subtracting the adjusted Stand Alone Base Case adminis-
trative value from the After-tax Auction Proceeds, and then adding to this difference
an additional credit to reconcile the FAS 109 Regulatory Asset balance. The credit
to reconcile the FAS 109 Regulatory Asset balance will be set equal to the 1999
beginning balance of \$179.00 million shown in Appendix G (at 2a).

An equivalent credit to the recoverable deferred taxes (“Deferred Tax Offset
Credit”) will also be applied. The Deferred Tax Offset Credit will be calculated as
the sum of two parts. The first part is calculated by multiplying the Market Value
Offset Credit subtracting the adjusted Stand Alone Base Case administrative value
from the After-tax Auction Proceeds, and then by multiplying this difference by the
fraction $(\text{Tax Rate}/(1-\text{Tax Rate}))$. At or approximately .71 for a statutory tax rate of
41.4935% this will provide a deferred tax credit (“The second part of the Deferred
Tax Offset Credit ”) will reconcile the deferred tax balance associated with the FAS
109 Regulatory Asset, and will be set equal to approximately \$0.71 for every dollar
of Market Value Offset Credit the 1999 beginning balance of \$57.48 million shown
in Appendix G (at 2a).

Continuing with our example, the derivation of these credits is shown in the
table below:

	(\$000)
Administrative Value	110,950
Adjustment for OCA Margin	27,000
Future Administrative Value	137,950
After-tax Auction Proceeds	<u>(352,594)</u>
Market Value Offset Credit <u>(without FAS 109 Adjustment)</u>	(214,644)
<u>FAS 109 Adjustment</u>	<u>(179,000)</u>
<u>Total Market Value Offset Credit</u>	<u>(393,644)</u>
Deferred Tax Offset Credit (152,228)	
(@ \$.71 per \$ <u>(152,228)</u>	
(without FAS 109 deferred tax adjustment)	
<u>FAS 109 Deferred Tax Adjustment</u>	<u>(57,480)</u>
<u>Total Deferred Tax Offset Credit</u>	<u>(209,708)</u>

E. Reconciliation with Interim CTC Revenues

The Restructuring Order provides if Duquesne divests its generating assets through an auction process, that beginning in 1999 an interim CTC may be charged to shopping customers based on the Pilot credits. Duquesne filed class specific residual CTC tariffs based on the Pilot credits in its Stand Alone Compliance Filing. The resulting Company average 1999 CTCs are approximately 2.7 cents (excluding GRT). The CTC revenues collected prior to completion of the auction will be allocable to ~~recovery of stranded costs, the~~ return on the unamortized balance of stranded costs, ~~and amortization of deferred taxes. However, the magnitude of the~~

Market Value Offset Credit and the Deferred Tax Offset Credit will not be known until the auction is completed. the recovery of the stranded cost balance and the amortization of the deferred tax balance.

The first step in the reconciliation process is to calculate a pro-forma set of monthly CTC revenue requirements (in the form of Appendix C of the Restructuring Order) beginning in 1999. The amount of Pilot CTC revenues allocated to return is based on the Stand Alone Base Case. However, the Compliance Order required Duquesne to calculate CTC revenue requirements that would produce average shopping credits equal to those produced in the Restructuring Order. Accordingly, within each year, the monthly pro-forma CTC revenue requirements provide for a levelized Commission's allowed 11% CTC return as calculated monthly on the unamortized CTC balance. The amount of Pilot CTC revenues allocated to recovery of the stranded cost balance and to the amortization of the deferred tax balance is determined such that the reduction in each balance is proportionate. Thus, during the interim Pilot CTC period, the proportion of total dollar value of recovery of stranded costs (calculated as a percentage of the 1999 beginning stranded cost balance) will be equal to the proportion of total dollar value of amortization of deferred taxes (calculated as a percentage of the 1999 beginning deferred tax balance). The sum of the three components so calculated (return, recovery and amortization) will be equal to the total dollar value of Pilot CTC

revenues collected at a fully grossed-up return of 11% and a levelized amortization of the associated deferred tax balances. However, the annual total CTC revenue requirement is constrained to produce an average shopping credit equal to 4.00 cents/kWh in 1999, 4.22 cents/kWh in 2000 and so forth, consistent with the shopping credits in the Restructuring Order.

Continuing with the example discussed above,

Appendix G (at 7a) shows the reconciliation of the unamortized balances of stranded costs and deferred taxes assuming forecast sales are realized. CTC revenue requirements under the Stand Alone Base Case in 1999 and 2000. In 1999, the total monthly revenue requirements pro-forma are \$27,000,000 consisting of \$22,847,259 of blended CTC recovery and return and \$4,152,741 of deferred tax amortization.

The 1999 pro-forma CTC revenue requirements under the Stand Alone Base Case are less than the CTC revenues that will be collected under the Pilot credit tariffs, assuming the forecast level of sales during the interim period is realized. At 1,098,149,355 kWh/month, the monthly 1999 CTC revenues recovered under the Pilot tariffs will be \$29,815,194.

Appendix G (at 8a) shows the reconciliation between the pro-forma CTC revenue requirements (based on the Stand Alone Base Case) and the 1999 interim CTC revenues collected (assuming the forecast sales under the Pilot Credit CTCs are

realized). The realized revenues are allocated between CTC recovery and return (84.62% of CTC revenue) and deferred tax amortization (15.38% of CTC revenue). The 84.62% portion of realized 1999 CTC revenues allocated to CTC recovery and return is further decomposed into the recovery of and return on the CTC balance of \$1,502 million.

Based on the 1999 CTC revenue collections (under the CTC Pilot credit tariffs) and the above allocation between the stranded cost and deferred tax components, the 1999 Ending Stranded Cost Balance will be ~~\$1,375,380,051~~ \$1,374,967,006 and the 1999 Ending Deferred Tax Balance will be ~~\$597,983,204~~ \$597,803,622. The Market Value Offset Credit of ~~\$214.6~~ \$393.6 million and the Deferred Tax Offset Credit of ~~\$152.2~~ \$209.7 million will be applied against these unamortized balances as shown in the table below.

	(\$000)
1999 Ending CTC Balance	1,375,380 <u>1,374,967</u>
Market Value Offset Credit	(214,644) <u>(393,644)</u>
2000 Beginning CTC Balance	1,160,736 <u>981,323</u>
1999 Ending DT Balance	597,983 <u>597,804</u>
Deferred Tax Offset Credit	(152,228) <u>(209,708)</u>
2000 Beginning DT Balance	445,755 <u>388,095</u>

F. Post-Auction CTC Design

Based on the above reconciliation of the year 2000 starting balances (after applying the Market Value Offset Credit and the Deferred Tax Offset Credit), the new balances can be reamortized using the same methodology as approved in the Compliance Order¹¹.

Appendix G (at 8a) shows the CTC revenue requirements¹² in 2000 and later that will result from targeting the Commission's approved Company average shopping credits set out in the Restructuring Order. Appendix G (at 9a) sets out the monthly equivalent of these CTC revenue requirements (i.e., for 2000 the monthly CTC revenue requirement is \$309,939,205 divided by 12, or \$25,828,267) assuming the Market Value Offset Credit and the Deferred Tax Offset Credit are applied at the beginning of 2000. ~~Again, using the CTC Revenue Requirements from the~~

¹¹ The Compliance Order (at 15-16) requires Duquesne to calculate CTC revenue requirements that would produce average shopping credits equal to those contained in the Restructuring Order. The resulting Company-wide CTC revenue requirements would be allocated to rate classes based on the production cost allocation methodology set out in Duquesne's compliance filing. Similarly, the actual reconciliation of the Pilot CTC revenues for each class would be based on an initial allocation of the total stranded cost and deferred tax balances at the beginning of 1999 using the production cost allocators. At the end of the interim period, the unamortized stranded cost and deferred tax balances for each class would receive an allocated share of the total Market Value Offset Credit and total Deferred Tax Offset Credit. The annual reconciliation of class CTC revenues to class CTC revenue requirements (as so determined after the application of the above credits), would be performed on a class specific basis with a recalculation of monthly recovery, return and deferred tax amortization based on actual sales volumes of that class. Within each year, the monthly pro-forma CTC revenue requirements provide for a recovery of stranded costs at a fully grossed-up return of 11% and a proportionate amortization of the associated deferred tax balance. Any underrecovery or overrecovery resulting from differences between forecast and actual sales for a particular class, would result in a lengthening or shortening of the recovery period for such class.

¹² Originally filed November 5, 1998 as part of Duquesne's revised compliance filing.

Compliance Order for illustrative purposes Appendix G (at 9a) shows how the remaining CTC and deferred tax balances are amortized over the remaining transition period. In each year the percentage amortization of the remaining CTC asset and remaining deferred tax balance are equivalent. Using the shopping credits from the Commission's Restructuring Order and the sales forecast and T&D rates from the most recent Company compliance filing, the CTC and Deferred Tax balances are fully amortized by year-end ~~2006~~ 2005.

----- COMPARISON OF FOOTNOTES -----

-FOOTNOTE 1-

The Commission's August 13, 1998 Opinion and Order on Duquesne's compliance filing (the "Compliance Order") adopted the Company's proposal for the interim CTC charges. Compliance Order at 12.

-FOOTNOTE 2-

Utility Assets ~~are those assets divested by Duquesne which have had their book values included for purposes of determining stranded costs. Assets~~ do not include assets that have been excluded by the Commission in determining its determination of stranded costs (e.g. (i.e., the non-rate base portions of the Brunot Island generating units) are not and the Phillips generating unit). Proceeds from these excluded assets will not be considered as Utility Assets for purposes of determining the Net Auction Proceeds. All other generating assets to be auctioned by Duquesne (including the assets exchanged with FirstEnergy Corporation ("FEC")) are included for purposes of determining stranded costs and are considered to be Utility Assets for purposes of the auction. Pursuant to its Agreement in Principle (the "Swap Agreement") to exchange certain generating asset with FEC, as filed with the Commission on

October 14, 1998, Duquesne will auction the wholly-owned fossil generating assets received from FEC (the "FEC Assets") rather than the partial interests in fossil and nuclear generating assets transferred to FEC (the "Transferred Assets"). The sum of the sales prices paid by the new owners for the FEC Assets will be included in the Net Auction Proceeds. The Transferred Assets will not be auctioned and thus not included in the Net Auction Proceeds. However, the book values used in the Commission's administrative determination of stranded costs as of January 1, 1999 will still be used for finally determining stranded costs based on the offset credits to stranded costs and to deferred taxes derived from the market values determined in the auction. In summary, book values are based on Duquesne's original generation assets and market values are based on the generation assets auctioned.

-FOOTNOTE 3-

The sales price shall be deemed to be zero for any Utility Asset for which a transfer is not completed, whether because no qualifying bids were received or because conditions precedent to such a transfer were not satisfied. In the event Duquesne receives a qualifying "negative bid" (See Section II.D., E. Qualifying Bids) that Duquesne is prepared to accept, the negative bid will be used to reduce the sum of the other non-negative sales prices for Utility Assets in determining the Net Auction Proceeds.

-FOOTNOTE 4-

~~The total includes a negative qualifying bid of \$15.0 million for Perry that includes a market determination of an additional \$5.0 million of required nuclear decommissioning funding in excess of that authorized for recovery by the Commission for Perry. The sum of the sales prices for all other assets is \$515 million, resulting in a total sum of \$500 million.~~ net tax effect of the implementing the Swap Agreement and auctioning the FEC Assets and Duquesne's remaining interest in Cheswick, Elrama, and the rate-based portion of Brunot Island, is that the tax basis of all auctioned assets will effectively be equal to the tax basis of Duquesne's generating assets as if the Swap Agreement had not been implemented. For purposes of the illustrative example, all references to the "tax basis of Utility Assets" divested are intended to refer to the tax basis of Duquesne's generating assets, including the Transferred Assets, and excluding the FEC Assets.

-FOOTNOTE 5-

Schedule MIK-1, December 1997 Update, Page 2 of 3.

-FOOTNOTE 6-

Restructuring Order at 123, 128.

-FOOTNOTE 7-

The Compliance Order was issued on August 13th and contains certain calculational errors. Duquesne ~~will correct~~ corrected those errors in its revised compliance filing. ~~The Stand Alone Base Case in Appendix G (at 2a) reflects the~~, and a description of the main corrections that Duquesne will seek to the Compliance Order is summarized here.

-FOOTNOTE 8-

For purposes of this summary calculation, the Restructuring Order's understatement of deferred tax balances by \$38.88 million has been attributed solely to Generating Plan Book. Duquesne took exception to this computational error in the Merger Compliance Filing. Page 2, note 2 clearly states that "Appendix A [to the Compliance Filing] also provides a description and break-down of the correct deferred tax balance associated with the Commission's administrative determination of stranded costs, while excluding the deferred taxes associated with disallowed cost items, including BI and Phillips. The Final Order does not explain how the deferred tax balance contained in Appendix D was derived, but it is not correct." The relevant pages of Appendix A to the Compliance Filing are reproduced here in Appendix G (at 4a-4c). The difference between the Commission's undocumented \$493.345 million deferred tax balance and Duquesne's detailed calculation of \$532.188 million

(Appendix G at 4b) is \$38.88 million, as adjusted for the 99.9% PA jurisdictional factor.

~~-FOOTNOTE 9-~~

The Commission recognizes that the divestiture may not be accomplished by January 1, 1999 and requires that the actual stranded utility generation value be reconciled. See Restructuring Order at 81-82.

~~-FOOTNOTE 10-~~

This assumes the closing occurs at year-end 1999. An earlier or later closing would require a different adjustment. The values at year-end 1998, 1999 and 2000 can be used to interpolate the adjustment if the closing of the auction occurs earlier in calendar 1999 or later in calendar year 2000.

~~-FOOTNOTE 11-~~

~~Under the Stand Alone Base Case a 1999 beginning stranded cost balance of \$1,502 million and deferred tax balance of \$653 million must be recovered through the CTC.~~

~~-FOOTNOTE 12-~~

~~Compliance Order at 15-16.~~

~~The Compliance Order provides that Duquesne's (at 15-16) requires Duquesne to calculate CTC revenue requirements that would produce average CTCs must be recalculated, adjusting for the new treatment of deferred taxes, the disallowance of the ECR roll-in and the recalculation of T&D rates, in order to produce the same shopping credits as equal to those contained in the Restructuring Order. This may require an extension of the recovery period and will result in different year-to-year CTC revenue requirements.~~

~~-FOOTNOTE 13-~~

~~For purposes of the example, we have assumed the total CTC Revenue Requirements are constrained to the values set out in the Commission Shopping Credit table to the Compliance Order. The resulting Company-wide actual constraints will be determined in Duquesne's next Compliance Filing.~~

~~-FOOTNOTE 14-~~

~~After application of the credits, the actual CTC revenue requirements would be recalculated to produce average shopping credits on a company-wide basis equal to those in the Restructuring Order. The resulting annual CTC revenue requirements would be allocated to rate classes based on the production cost allocation~~

methodology set out in Duquesne's Duquesne's compliance filing. Similarly, the actual reconciliation of the Pilot CTC revenues for each class would be based on an initial allocation of the total stranded cost and deferred tax balances at the beginning of 1999 using the production cost allocators. At the end of the interim period, the unamortized stranded cost and deferred tax balances for each class would receive an allocated share of the total Market Value Offset Credit and total Deferred Tax Offset Credit. The annual reconciliation of class CTC revenues to class CTC revenue requirements (as so determined after the application of the above credits), would be performed on a class specific basis with a recalculation of monthly recovery, return and deferred tax amortization based on actual sales volumes of that class. Within each year, the monthly pro-forma CTC revenue requirements provide for a recovery of stranded costs at a fully grossed-up return of 11% and a proportionate amortization of the associated deferred tax balance. Any underrecovery or overrecovery resulting from differences between forecast and actual sales for a particular class, would result in a lengthening or shortening of the recovery period for such class.

-FOOTNOTE 12-

Originally filed November 5, 1998 as part of Duquesne's revised compliance filing.

----- COMPARISON OF FOOTERS -----

-FOOTER 1-

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DUQUESNE LIGHT COMPANY

Owned-Generation Stranded Cost Summary
Before Adjustments
(millions \$)

Plant	Net Book Value @ 12/31/98	NPV Net Margins ⁽¹⁾	NPV Decommissioning Cost ⁽³⁾	Initial Stranded Cost
Perry	\$232.34	\$0	\$18.93	\$ 251.27
Beaver Valley 1	212.14	0	17.52	229.66
Beaver Valley 2 ⁽⁴⁾	545.84	0	8.02	553.86
Elrama	90.39	0	-	90.39
Cheswick	105.46	(36.9)	-	142.36
Mansfield	94.81	129.6	-	(34.79)
Sammis	33.31	3.4	-	29.91
Eastlake	30.97	0	-	30.97
Brunot Island	<u>17.06</u>	<u>0</u>	<u>-</u>	<u>17.06</u>
Owned-Units Subtotal	\$1,362.32	\$99.4 ⁽²⁾	\$44.47	\$1,307.39
Working Capital	\$61.53	\$15.91	-	\$ 45.62
Cold Reserve Plants ⁽⁵⁾	<u>\$64.06</u>	<u>\$0.00</u>	<u>-</u>	<u>\$ 64.06</u>
Total	\$1,487.91	\$115.31	\$44.47	\$1,417.07

⁽¹⁾ Excludes fossil decommissioning costs. Negative net margins are treated as zero.

⁽²⁾ The total has been increased by 3.4 percent (a half-year of discounting) to account for the fact that Duquesne's cash flow model applies a full year discount in the first year.

⁽³⁾ Source: Schedule TSC-2. Mr. Catlin's annual revenue requirement for 1999-2005 is converted to a NPV amount at 1/1/99 using a 6.88 percent discount rate.

⁽⁴⁾ Beaver Valley 2 amount is the sum of reported net book value (\$32.48 million) plus the NPV of the lease (\$513.36 million). Source: Schedule TSC-1.

⁽⁵⁾ This includes \$3.48 million of remaining net book value for the Warwick mine at 12/31/98.

**Stranded Cost Allowance
with Associated Deferred Taxes
(\$Millions)**

Stand Alone Base Case

<u>Category/Item:</u>	<u>Deferred Taxes</u>	<u>Amount</u>
Duquesne Light Restructuring		
Book Value:		
Generating Plant Book Value	\$ 411.34	\$ 852.03
Beaver Valley 2 Lease PV	\$ 213.01	\$ 300.35
M&S Fuel Related Sunk Costs	-	-
Working Capital	-	\$ 61.53
Costs Independent of Operation	-	-
Generation Market Value	\$ (78.69)	\$ (110.95)
Merger Savings	\$ -	\$ -
<u>Total Stranded Generation:</u>	\$ 545.66	\$ 1,102.96
<u>Decommissioning:</u>		
Nuclear Decommissioning	-	\$ 42.96
Fossil Decommissioning	-	-
Total Decommissioning	\$ -	\$ 42.96
<u>Regulatory Assets:</u>		
FAS 109 (including Plant reversal)	\$ 57.48	\$ 179.00
Post '05 Unamortized Debt Costs	\$ 10.67	\$ 18.67
Pre '06 Unamortized Debt Costs	\$ 6.82	\$ 9.61
Deferred Rate Synch. (Early Window)	\$ 1.87	\$ 23.50
Deferred Employee Costs	-	\$ 14.24
Deferred Nuclear Maintenance	\$ 1.35	\$ 1.90
US DOE Decommissioning	\$ 2.33	\$ 3.25
Deferred Coal Costs	-	-
Deferred Caretaker Costs	-	-
Pre-Accrued Nuclear Outage	-	-
BV2 Training Costs	\$ 0.84	\$ 1.58
Low Level Radioactive Waste	-	\$ 2.27
Coal Cost Equalization	-	\$ 0.12
Transition Costs	\$ 7.51	\$ 10.59
SFAS 106 Deferral	\$ 1.40	\$ 1.97
Deferred Fuel Costs	\$ 17.73	\$ 25.00
Other Regulatory Assets	-	\$ 0.53
Consumer Education	-	\$ 10.00
Sale-Leaseback Tax Effect (Gain)	-	\$ 55.13
Deferred Rate Synch. Costs	-	-
BV2 Tax Effect	-	\$ 0.17
<u>Total Regulatory Assets:</u>	\$ 108.00	\$ 357.53
PA Jurisdictional % (1-FERC Allocation)	99.900%	99.900%
TOTAL STRANDED, STAND ALONE	\$ 653.012	\$ 1,501.948
WITH JURISDICTIONAL ALLOCATION		

Stranded Cost Allowance
(\$Millions)

<u>Category/Item:</u>	<u>Amount</u>
Duquesne Light Restructuring	
Book Value:	
Generating Plant Book Value	\$ 852.03
Beaver Valley 2 Lease PV	\$ 300.35
M&S Fuel Related Sunk Costs	-
Working Capital	\$ 61.53
Costs Independent of Operation	-
Generation Market Value	\$ (110.95)
Merger Savings	\$ (152.28)
Total Stranded Generation:	\$ 950.68
Decommissioning:	
Nuclear Decommissioning	\$ 42.96
Fossil Decommissioning	-
Total Decommissioning	\$ 42.96
Regulatory Assets:	
FAS 109 (including Plant reversal)	\$ 179.00
Post '05 Unamortized Debt Costs	\$ 18.67
Pre '08 Unamortized Debt Costs	\$ 9.61
Deferred Rate Synch. (Early Window)	\$ 23.50
Deferred Employee Costs	\$ 14.24
Deferred Nuclear Maintenance	\$ 1.90
US DOE Decommissioning	\$ 3.25
Deferred Coal Costs	-
Deferred Caretaker Costs	-
Pre-Accrued Nuclear Outage	-
BV2 Training Costs	\$ 1.58
Low Level Radioactive Waste	\$ 2.27
Coal Cost Equalization	\$ 0.12
Transition Costs	\$ 10.58
SFAS 106 Deferral	\$ 1.97
Deferred Fuel Costs	\$ 6.73
Other Regulatory Assets	\$ 0.53
Consumer Education	\$ 10.00
Sale-Leaseback Tax Effect (Gain)	\$ 55.13
Deferred Rate Synch. Costs	-
BVZ Tax Effect	\$ 0.17
Total Regulatory Assets:	\$ 339.26
PA Jurisdictional % (1-FERC Allocation)	99.800%
TOTAL STRANDED, WITH MERGER AND JURISDICTIONAL ALLOCATION	\$ 1,331.567

Discussion re: Deferred Taxes in PaPUC Decision

The May 29, 1998 Opinion and Order of the Commission determined and allowed recovery of stranded costs for Duquesne in the amount of \$1,331,567,100 in the event the merger with Allegheny is consummated. Attachment B to the Order summarizes the individual components of stranded costs (net of tax) allowed by the Commission under the merger case. Attachment D to the Order identifies a Deferred Tax Principal balance of \$493,344,701 associated with this stranded cost determination. The Order contains no equivalent breakout of the individual components of the deferred tax total comparable to that of stranded costs presented in Attachment B.

The April 13, 1998 Exceptions of Duquesne to the ALJ Recommended Decision included an Appendix B that presented a Revised Exhibit No. DJC-10 summarizing the stranded cost recommendations of Duquesne, the OCA and the ALJ. Appendix B presented both Gross and Net stranded cost components, and the deferred tax balances associated with each component.

Duquesne believes the Commission has referred to the component breakout presented in Appendix B to Duquesne's Exceptions in deriving the deferred tax total presented in Attachment D to the Order. However, the Company has been unable to replicate the derivation of the Order's \$493,344,701 deferred tax balance.

The attached table "Stranded Cost Allowance with Associated Deferred Taxes" is based on Attachment B to the Commission's Order and Appendix B of Duquesne's Exceptions. The table presents an associated deferred tax balance for each component allowed by the Commission in the merger case. These balances are based on the deferred tax recommendations of the ALJ (for components allowed by the Order) as set out in Revised Exhibit No. DJC-10, except as otherwise shown in the Notes on Deferred Taxes below.

Notes on Deferred Taxes:

- 1) The balance of \$411.34 MM reflects an addition of \$2.56 MM (to the ALJ's balance of \$408.78 MM) for deferred taxes associated with the Warwick Mine plant balance, that was allowed by the Order, but not included in the ALJ's recommended decision. Note that deferred taxes associated with Brunot Island and Phillips were not included in the ALJ balance of \$408.92 MM. See Note ALJ-1, Appendix B, DLC Exceptions.
- 2) The Order determined a generation market value of \$110.95 MM, less than the \$286.03 MM value recommended by the ALJ. In Appendix B, the associated reduction in the deferred taxes associated with the ALJ's recommended market value is \$202.86 MM. Duquesne has calculated an inputted reduction of \$78.69 MM for the Order's market value based on a tax rate of 41.4935%.
- 3) The Order has adopted the OCA's recommended value for certain Regulatory Assets. The deferred tax balances reflect the OCA's values shown in Appendix B, DLC Exceptions.
- 4) The deferred taxes associated with the Deferred Fuel Costs reflect the Order's value of \$6.73 MM and have not been updated through May 29, 1998.

Stranded Cost Allowance
with Associated Deferred Taxes
(\$Millions)

<u>Category/Item:</u>	<u>Deferred Taxes</u>	<u>Amount</u>
Duquesne Light Restructuring		
Book Value:		
Generating Plant Book Value (1)	\$ 411.34	\$ 852.03
Beaver Valley 2 Lease PV	\$ 213.01	\$ 300.35
M&S Fuel Related Sunk Costs	-	-
Working Capital	-	\$ 61.53
Costs Independent of Operation	-	-
Generation Market Value (2)	\$ (78.69)	\$ (110.95)
Merger Savings	\$ (107.99)	\$ (152.28)
Total Stranded Generation:	\$ 437.67	\$ 950.68
Decommissioning:		
Nuclear Decommissioning	-	\$ 42.96
Fossil Decommissioning	-	-
Total Decommissioning	\$ -	\$ 42.96
Regulatory Assets:		
FAS 109 (including Plant reversal)	\$ 57.48	\$ 179.00
Post '05 Unamortized Debt Costs (3)	\$ 10.67	\$ 18.67
Pre '06 Unamortized Debt Costs (3)	\$ 6.82	\$ 9.61
Deferred Rate Synch. (Early Window)	\$ 1.87	\$ 23.50
Deferred Employee Costs	-	\$ 14.24
Deferred Nuclear Maintenance	\$ 1.35	\$ 1.90
US DOE Decommissioning	\$ 2.33	\$ 3.25
Deferred Coal Costs	-	-
Deferred Caretaker Costs	-	-
Pre-Accrued Nuclear Outage	-	-
BV2 Training Costs	\$ 0.84	\$ 1.58
Low Level Radioactive Waste	-	\$ 2.27
Coal Cost Equalization	-	\$ 0.12
Transition Costs	\$ 7.51	\$ 10.59
SFAS 106 Deferral (3)	\$ 1.40	\$ 1.97
Deferred Fuel Costs (4)	\$ 4.78	\$ 6.73
Other Regulatory Assets	-	\$ 0.53
Consumer Education	-	\$ 10.00
Sale-Leaseback Tax Effect (Gain)	-	\$ 55.13
Deferred Rate Synch. Costs	-	-
BV2 Tax Effect	-	\$ 0.17
Total Regulatory Assets:	\$ 95.05	\$ 339.26
PA Jurisdictional % (1-FERC Allocation)	99.900%	99.900%
TOTAL STRANDED, WITH MERGER AND JURISDICTIONAL ALLOCATION	\$532.188	\$ 1,331.567

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

Duquesne Light Company

Total Stranded Cost Determination
 As of December 31, 1998
 (\$ Millions)

	DLCo			OCA			ALJ			Notes
	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	\$1,257.33	\$408.78	\$848.55	(ALJ-1)
Working Capital	0.00	0.00	0.00	61.53	0.00	61.53	61.53	0.00	61.53	(ALJ-2)
M&S and Fuel-Related Sunk Costs	41.11	0.00	41.11	0.00	0.00	0.00	41.11	0.00	41.11	(ALJ-3)
PV of BV2 Lease Expense (1)	475.57	197.33	278.24	513.36	213.01	300.35	513.36	213.01	300.35	(ALJ-4)
Net Book Value	1,887.21	650.25	1,236.96	1,940.83	665.93	1,274.90	1,873.33	621.79	1,251.54	
P V of Decommissioning	123.90	0.00	123.90	44.47	0	44.47	44.47	0.00	44.47	(ALJ-5)
PV of Costs Independent of Operation	208.23	0.00	208.23	0	0	0.00	208.23	0.00	208.23	(ALJ-6)
Estimated Market Value	(46.83)	(19.43)	(27.40)	(511.17)	(212.10)	(299.07)	(488.89)	(202.86)	(286.03)	(ALJ-7)
Stranded Generating Plant	2,172.51	630.82	1,541.69	1,474.13	453.83	1,020.30	1,637.14	418.93	1,218.21	
Regulatory Assets										
SFAS 109	\$236.48	\$57.48	\$179.00	\$236.48	\$57.48	\$179.00	\$236.48	\$57.48	\$179.00	(ALJ-8)
Post-2005 - Unamortized Debt Cost	29.92	10.88	19.04	29.34	10.67	18.67	29.92	10.88	19.04	(ALJ-9)
Pre-2006 - Unamortized Debt Cost	16.76	6.96	9.80	16.43	6.82	9.61	16.76	6.96	9.80	(ALJ-9)
Deferred Rate Sync. Costs	25.37	1.87	23.50	26.52	1.95	24.57	25.37	1.87	23.50	(ALJ-10)
Deferred Employee Costs	13.83	0.00	13.83	14.24	0.00	14.24	13.83	0.00	13.83	(ALJ-10)
Deferred Nuclear Maintenance	3.25	1.35	1.90	3.25	1.35	1.90	3.25	1.35	1.90	
DOE Decom and Decon.	5.58	2.33	3.25	5.74	2.40	3.34	5.58	2.33	3.25	(ALJ-10)
Deferred Coal Costs	13.50	0.00	13.50	0.00	0.00	0.00	0.00	0.00	0.00	(ALJ-11)
Deferred Caretaker Costs	6.77	2.85	3.92	0.00	0.00	0.00	0.00	0.00	0.00	(ALJ-12)
BV2 Training Costs	2.42	0.84	1.58	2.42	0.84	1.58	2.42	0.84	1.58	
Low Level Rad. Waste	2.27	0.00	2.27	2.27	0.00	2.27	2.27	0.00	2.27	
Coal Cost Equalization	0.12	0.00	0.12	0.12	0.00	0.12	0.12	0.00	0.12	
Other	0.53	0.00	0.53	0.53	0.00	0.53	0.53	0.00	0.53	
Pre-Accrue Nuclear Outages	17.60	7.31	10.29	0.00	0.00	0.00	17.60	7.31	10.29	(ALJ-13)
Gain on Sale/Leaseback	55.13	0.00	55.13	55.13	0.00	55.13	55.13	0.00	55.13	
Deferred Rate Sych. Costs (Tax)	0.21	0.00	0.21	0.22	0.00	0.22	0.21	0.00	0.21	(ALJ-10)
BV-2 (Tax)	0.17	0.00	0.17	0.17	0.00	0.17	0.17	0.00	0.17	
Deferred Fuel Cost	11.51	4.78	6.73	11.84	4.92	6.92	11.51	4.78	6.73	(ALJ-10)
Transition Costs	18.10	7.51	10.59	18.20	7.61	10.59	18.10	7.51	10.59	(ALJ-14)
SFAS 106	3.28	1.36	1.92	3.37	1.40	1.97	0.00	0.00	0.00	(ALJ-15)
SFAS 109 Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(ALJ-16)
Total Regulatory Assets	462.80	105.52	357.28	426.27	95.44	330.83	439.25	101.31	337.94	
Total Stranded Cost (Standalone)	\$2,635.31	\$736.34	\$1,898.97	\$1,900.40	\$549.27	\$1,351.13	\$2,076.39	\$520.24	\$1,556.15	
Merger Savings	0.00	0.00	0.00	(260.27)	(107.99)	(152.28)	(260.27)	(107.99)	(152.28)	(ALJ-17)
Total Stranded Cost (w/ Merger Savings)	\$2,635.31	\$736.34	\$1,898.97	\$1,640.13	\$441.28	\$1,198.85	\$1,816.12	\$412.25	\$1,403.87	

DUQUESNE LIGHT COMPANY

Owned-Generation OCA Margin Summary

<u>Plant</u>	12/31/98 NPV <u>Net Margins</u>	12/31/99 NPV <u>Net Margins</u>	12/31/00 NPV <u>Net Margins</u>
Perry	\$0	\$0	\$0
Beaver Valley 1	0	0	8.4
Beaver Valley 2	0	0	0
Elrama	0	0	0
Cheswick	(36.9)	(25.9)	(10.9)
Mansfield	129.6	139.5	148.9
Sammis	3.4	8.4	11.5
Eastlake	0	0	0
Brunot Island	0	0.3	1.1
Owned-Units Subtotal *	\$99.4	\$126.3	\$164.5
Difference from 12/31/98	0.0	27.0	65.1

* The Owned-Units Subtotal has been increased by 3.4%, one half year's discounting, to accord with Schedule MIK-1 December 1997 Update Page 2 of 3 as reproduced at Appendix G at 8.

DUQUESNE LIGHT**Costs of Fossil Plants**

\$ in Millions

	Fuel Forecast Provided By Doug Smith						Fuel Forecast Provided By Doug Smith								
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMARY FOR FOSSIL PLANTS - AFTER TAX															
CHESWICK															
Direct Margin	(9.66)	(12.14)	(9.49)	(5.70)	(2.20)	(23.63)	8.14	10.57	12.60	15.80	18.89	6.92	26.11	34.08	38.18
Margin after Corp O/H	(13.48)	(16.84)	(14.34)	(10.79)	(8.88)	(33.83)	(0.49)	1.12	2.35	5.22	7.90	(6.80)	14.33	21.71	24.61
SAMMIS															
Direct Margin	(2.19)	(0.07)	(4.04)	0.72	3.93	5.57	5.35	7.29	4.14	9.45	9.85	11.55	0.00	0.00	0.00
Margin after Corp O/H	(4.77)	(2.54)	(7.22)	(1.97)	1.16	3.04	2.49	4.48	0.47	6.39	6.64	8.27	0.00	0.00	0.00
EASTLAKE															
Direct Margin	(3.45)	(2.70)	(6.04)	(5.43)	1.23	(0.04)	0.26	2.26	3.73	4.40	5.04	4.66	6.42	0.00	0.00
Margin after Corp O/H	(4.34)	(3.56)	(7.48)	(7.09)	(0.11)	(1.71)	(1.78)	0.30	1.61	1.98	2.47	1.81	3.18	0.00	0.00
ELRAMA															
Direct Margin	(9.66)	(10.01)	(8.63)	(3.11)	5.39	8.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Margin after Corp O/H	(17.26)	(18.25)	(16.85)	(11.17)	(2.84)	0.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MANSFIELD 1															
Direct Margin	(1.77)	(6.76)	(5.08)	(4.46)	(4.00)	(3.43)	(2.23)	(3.63)	(1.14)	(0.63)	(2.47)	(0.11)	0.54	(0.34)	3.09
Margin after Corp O/H	(3.36)	(9.34)	(7.40)	(6.89)	(6.65)	(5.90)	(4.77)	(6.54)	(3.90)	(3.36)	(5.76)	(3.16)	(2.63)	(4.02)	(0.34)
MANSFIELD 2															
Direct Margin	0.15	0.37	(0.52)	0.87	1.91	1.52	2.61	2.92	2.43	3.95	3.81	3.90	5.09	5.80	5.44
Margin after Corp O/H	(0.57)	(0.38)	(1.45)	0.08	1.09	0.63	1.79	2.07	1.37	3.06	2.82	2.83	4.10	4.74	4.12
MANSFIELD 3															
Direct Margin	2.11	3.06	2.85	3.18	8.91	9.19	10.30	12.38	13.83	14.08	16.43	18.13	19.37	23.46	25.46
Margin after Corp O/H	(0.33)	0.54	0.21	0.27	6.21	6.48	7.43	9.44	10.78	10.76	13.14	14.72	15.88	19.88	21.66
BRUNOT ISLAND															
Direct Margin	(1.50)	(0.67)	(0.68)	(0.48)	0.71	(1.74)	0.80	0.83	0.88	0.93	0.98	1.02	1.09	1.74	0.00
Margin after Corp O/H	(1.79)	(0.82)	(0.83)	(0.66)	0.55	(2.27)	0.61	0.64	0.68	0.71	0.79	0.84	0.89	1.61	0.00

DUQUESNE LIGHT

Costs of Fossil Plants

\$ in Millions

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	
SUMMARY FOR FOSSIL PLANT														6.88%
CHESWICK														
Direct Margin	45.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.4
Margin after Corp O/H	31.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(36.9)
SAMMIS														
Direct Margin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.4
Margin after Corp O/H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.4
EASTLAKE														
Direct Margin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.8)
Margin after Corp O/H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(15.7)
ELRAMA														
Direct Margin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(17.8)
Margin after Corp O/H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(56.1)
MANSFIELD 1														
Direct Margin	4.42	2.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(22.6)
Margin after Corp O/H	0.88	(2.06)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(49.5)
MANSFIELD 2														
Direct Margin	7.32	7.05	7.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.9
Margin after Corp O/H	6.22	5.68	6.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.5
MANSFIELD 3														
Direct Margin	26.54	28.81	30.27	30.43	32.53	33.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	146.5
Margin after Corp O/H	22.35	24.34	26.40	26.43	28.07	29.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	112.1
BRUNOT ISLAND														
Direct Margin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.4
Margin after Corp O/H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(1.4)

6.88%
NPV@'99

DUQUESNE LIGHT
Costs of Nuclear Plants

\$ in Millions

	Fuel Forecast Provided By Doug Smith				Fuel Forecast Provided By Doug Smith													
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
SUMMARY FOR NUCLEAR PLANTS																		
BEAVER VALLEY 1																		
Direct Margin	(15.13)	(9.43)	(1.62)	(8.26)	0.45	9.08	1.67	3.01	14.03	6.47	6.98	19.86	12.13	15.01	30.29	20.09	36.35	0.00
Margin after Corp O/H	(21.95)	(15.68)	(6.87)	(15.00)	(6.24)	3.94	(5.35)	(4.55)	7.82	(1.60)	(1.35)	12.99	3.09	5.51	22.06	9.73	27.09	0.00
BEAVER VALLEY 2																		
Direct Margin	(6.14)	(2.14)	(4.31)	(3.60)	0.46	(1.38)	(1.01)	1.25	(0.50)	0.07	2.65	0.67	1.36	5.17	3.02	3.80	7.19	4.57
Margin after Corp O/H	(8.38)	(3.90)	(6.46)	(5.81)	(1.40)	(3.51)	(3.31)	(0.86)	(3.07)	(2.56)	0.32	(2.19)	(1.59)	2.50	(0.41)	0.40	3.89	1.18
PERRY																		
Direct Margin	(16.22)	(11.90)	(15.04)	(11.50)	(10.71)	(8.44)	(10.23)	(7.54)	(9.37)	(6.23)	(8.40)	(5.43)	(6.85)	(2.41)	(5.01)	(0.45)	(2.99)	0.68
Margin after Corp O/H	(20.61)	(15.86)	(19.64)	(15.75)	(15.25)	(12.52)	(14.95)	(12.17)	(14.62)	(11.09)	(13.87)	(10.61)	(12.68)	(8.02)	(11.65)	(6.47)	(10.41)	(5.25)

DUQUESNE LIGHT

Costs of Nuclear Plan

\$ in Millions

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	
SUMMARY FOR NUCLEAR P											6.88%
BEAVER VALLEY 1											NPV @ '99
Direct Margin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.4
Margin after Corp O/H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(26.9)
BEAVER VALLEY 2											
Direct Margin	4.78	8.24	5.23	5.46	9.31	5.96	6.23	10.52	6.79	7.09	10.2
Margin after Corp O/H	1.42	4.93	1.47	1.29	5.59	1.33	1.62	5.88	1.67	1.39	(23.2)
PERRY											
Direct Margin	(2.56)	1.38	(2.09)	2.14	(1.49)	2.96	(0.72)	3.84	0.11	4.79	(91.1)
Margin after Corp O/H	(8.98)	(5.33)	(9.19)	(4.99)	(9.63)	(4.87)	(9.19)	(5.26)	(9.18)	(4.64)	(157.7)

First Year Pilot Revenues

	Revenue Requirements		Allocation of Pilot Revenues
Average Monthly CTC	\$ 23,823,470	83.81%	\$ 23,823,470
Average Monthly Deferred Tax	\$ 4,600,698	16.19%	\$ 4,600,698
Total Monthly	\$ 28,424,169	100.00%	\$ 28,424,169

Total CTC Revenue Requirement: Return Of & On Stranded Costs + Return Of Unamortized Cost Deferred Tax Balance
 Total Monthly CTC Revenues based on Pilot Credit Average Residual CTC of \$0.027246.

Month	Monthly kwh	Deferred Tax	Stranded Beg. of Month	Deferred Tax Beg. of Month	Stranded Cost Revenues	Deferred Tax Revenues	Total Monthly CTC Revenues	Def Tax %	Stranded %	Return %	Amort %
		\$ 653,012,000									
		Stranded	\$ 1,501,948,000								
1	1,043,241,887	\$ 1,501,948,000	\$ 653,012,000	\$ 23,982,904	\$ 4,441,265	\$ 28,424,169	15.62%	84.38%	48.44%	35.94%	
2	1,043,241,887	\$ 1,491,732,953	\$ 648,570,735	\$ 23,954,529	\$ 4,469,639	\$ 28,424,169	15.72%	84.28%	48.11%	36.17%	
3	1,043,241,887	\$ 1,481,452,642	\$ 644,101,096	\$ 23,925,973	\$ 4,498,196	\$ 28,424,169	15.83%	84.17%	47.78%	36.40%	
4	1,043,241,887	\$ 1,471,106,652	\$ 639,602,900	\$ 23,897,234	\$ 4,526,934	\$ 28,424,169	15.93%	84.07%	47.44%	36.63%	
5	1,043,241,887	\$ 1,460,694,562	\$ 635,075,966	\$ 23,868,312	\$ 4,555,856	\$ 28,424,169	16.03%	83.97%	47.11%	36.87%	
6	1,043,241,887	\$ 1,450,215,950	\$ 630,520,110	\$ 23,839,205	\$ 4,584,963	\$ 28,424,169	16.13%	83.87%	46.77%	37.10%	
7	1,043,241,887	\$ 1,439,670,391	\$ 625,935,146	\$ 23,809,912	\$ 4,614,256	\$ 28,424,169	16.23%	83.77%	46.43%	37.34%	
8	1,043,241,887	\$ 1,429,057,457	\$ 621,320,890	\$ 23,780,432	\$ 4,643,736	\$ 28,424,169	16.34%	83.66%	46.09%	37.58%	
9	1,043,241,887	\$ 1,418,376,718	\$ 616,677,154	\$ 23,750,764	\$ 4,673,405	\$ 28,424,169	16.44%	83.56%	45.74%	37.82%	
10	1,043,241,887	\$ 1,407,627,741	\$ 612,003,749	\$ 23,720,906	\$ 4,703,263	\$ 28,424,169	16.55%	83.45%	45.40%	38.06%	
11	1,043,241,887	\$ 1,396,810,090	\$ 607,300,486	\$ 23,690,857	\$ 4,733,312	\$ 28,424,169	16.65%	83.35%	45.05%	38.30%	
12	1,043,241,887	\$ 1,385,923,325	\$ 602,567,174	\$ 23,660,616	\$ 4,763,552	\$ 28,424,169	16.76%	83.24%	44.70%	38.55%	

Ending Deferred Tax Balance	\$ 597,803,622
Ending Stranded Balance	\$ 1,374,967,006

Decomposition of Pilot Revenues

Month	Return	Recovery	Ending Balance
1	\$ 13,767,857	\$ 10,215,047	\$ 1,491,732,953
2	\$ 13,674,219	\$ 10,280,310	\$ 1,481,452,642
3	\$ 13,579,983	\$ 10,345,990	\$ 1,471,106,652
4	\$ 13,485,144	\$ 10,412,090	\$ 1,460,694,562
5	\$ 13,389,700	\$ 10,478,612	\$ 1,450,215,950
6	\$ 13,293,646	\$ 10,545,559	\$ 1,439,670,391
7	\$ 13,196,979	\$ 10,612,934	\$ 1,429,057,457
8	\$ 13,099,693	\$ 10,680,739	\$ 1,418,376,718
9	\$ 13,001,787	\$ 10,748,977	\$ 1,407,627,741
10	\$ 12,903,254	\$ 10,817,651	\$ 1,396,810,090
11	\$ 12,804,092	\$ 10,886,765	\$ 1,385,923,325
12	\$ 12,704,297	\$ 10,956,319	\$ 1,374,967,006

Duquesne Light Company

CTC, T&D and Shopping Credit in Cents per kwh

Pre-Tax Return: 11.00%

Year	kwh consumed (1)	CTC Revenue Requirement (2)	CTC Rate With GRT (3)	T&D Rate (4)	Bundled Rate Today (5)	Shopping Credit (6)
1999	12,518,902,647	\$ 341,090,023	2.85	2.140	8.78	3.79
2000	13,396,867,288	\$ 309,939,205	2.42	2.140	8.78	4.22
2001	13,617,281,321	\$ 303,322,219	2.33	2.140	8.78	4.31
2002	13,845,460,353	\$ 296,492,227	2.24	2.140	8.78	4.40
2003	14,082,528,386	\$ 288,106,000	2.14	2.140	8.78	4.50
2004	14,331,562,413	\$ 278,129,767	2.03	2.140	8.78	4.61
2005	14,587,560,447	\$ 263,573,878	1.89	2.140	8.78	4.75

Notes:

- (1) OCA's retail kWh for 1999 (PaPUC-mandated level). Thereafter, Duquesne's sales forecast was used.
- (2) CTC collections in 1999 are calculated as a residual using methodology from the pilot. Thereafter, the CTC rates (post-auction) are set at levels to produce shopping credits in the May PaPUC order. The length of the CTC recovery period will be shortened or lengthened depending on the results of Duquesne's auction of generating assets and actual retail sales.
- (3) GRT Gross up is 1/(1-GRT), or 1.0460251, to reflect payment of the portion of the GRT on the GRT revenue receipt.
- (4) Figures are illustrative beyond June 2001 when the cap on non-generation charges expires.
- (5) The ECR roll-in in bundled rates is based on the PaPUC-mandated level of fuel and purchased power costs of \$12.80 per MWH.
- (6) Shopping credits in 1999 are based on the pilot methodology. Thereafter, shopping credits (post-auction) are set at levels consistent with the May PaPUC Order. Shopping credits include energy and capacity, T&D losses, ancillary services, and GRT.

Post-Auction CTC Calculation						
Total CTC Revenue Requirement: Return Of & On Stranded Costs + Return Of Unamortized Cost Deferred Tax Balance						
After Market Value Offset Credit and Deferred Tax Offset Credit						
	Deferred Tax	\$ 388,095,441			Monthly Return:	Annual Return:
	Stranded	\$ 981,322,831		Stranded	0.9167%	11.000%
Month	Monthly kwh	Stranded Beg. of Month	Deferred Tax Beg. of Month	Stranded Cost Revenue Requirement	Deferred Tax Revenue Req.	Total Monthly Revenue Req.
13	1,116,405,607	\$ 981,322,831	\$ 388,095,441	\$ 21,057,821	\$ 4,770,446	\$ 25,828,267
14	1,116,405,607	\$ 969,260,469	\$ 383,324,995	\$ 21,026,485	\$ 4,801,782	\$ 25,828,267
15	1,116,405,607	\$ 957,118,872	\$ 378,523,213	\$ 20,994,943	\$ 4,833,324	\$ 25,828,267
16	1,116,405,607	\$ 944,897,519	\$ 373,689,888	\$ 20,963,194	\$ 4,865,073	\$ 25,828,267
17	1,116,405,607	\$ 932,595,886	\$ 368,824,815	\$ 20,931,236	\$ 4,897,031	\$ 25,828,267
18	1,116,405,607	\$ 920,213,446	\$ 363,927,784	\$ 20,899,068	\$ 4,929,199	\$ 25,828,267
19	1,116,405,607	\$ 907,749,667	\$ 358,998,585	\$ 20,866,689	\$ 4,961,578	\$ 25,828,267
20	1,116,405,607	\$ 895,204,017	\$ 354,037,007	\$ 20,834,097	\$ 4,994,170	\$ 25,828,267
21	1,116,405,607	\$ 882,575,956	\$ 349,042,837	\$ 20,801,292	\$ 5,026,975	\$ 25,828,267
22	1,116,405,607	\$ 869,864,944	\$ 344,015,861	\$ 20,768,270	\$ 5,059,997	\$ 25,828,267
23	1,116,405,607	\$ 857,070,436	\$ 338,955,865	\$ 20,735,032	\$ 5,093,235	\$ 25,828,267
24	1,116,405,607	\$ 844,191,883	\$ 333,862,630	\$ 20,701,576	\$ 5,126,692	\$ 25,828,267
25	1,134,773,443	\$ 831,228,733	\$ 328,735,938	\$ 20,272,756	\$ 5,004,096	\$ 25,276,852
26	1,134,773,443	\$ 818,575,573	\$ 323,731,842	\$ 20,239,885	\$ 5,036,967	\$ 25,276,852
27	1,134,773,443	\$ 805,839,298	\$ 318,694,876	\$ 20,206,798	\$ 5,070,054	\$ 25,276,852
28	1,134,773,443	\$ 793,019,360	\$ 313,624,822	\$ 20,173,494	\$ 5,103,358	\$ 25,276,852
29	1,134,773,443	\$ 780,115,211	\$ 308,521,464	\$ 20,139,971	\$ 5,136,881	\$ 25,276,852
30	1,134,773,443	\$ 767,126,296	\$ 303,384,583	\$ 20,106,227	\$ 5,170,624	\$ 25,276,852
31	1,134,773,443	\$ 754,052,060	\$ 298,213,959	\$ 20,072,263	\$ 5,204,589	\$ 25,276,852
32	1,134,773,443	\$ 740,891,941	\$ 293,009,370	\$ 20,038,075	\$ 5,238,777	\$ 25,276,852
33	1,134,773,443	\$ 727,645,376	\$ 287,770,593	\$ 19,999,662	\$ 5,273,190	\$ 25,276,852
34	1,134,773,443	\$ 714,311,797	\$ 282,497,403	\$ 19,969,023	\$ 5,307,828	\$ 25,276,852
35	1,134,773,443	\$ 700,890,631	\$ 277,189,575	\$ 19,934,157	\$ 5,342,694	\$ 25,276,852
36	1,134,773,443	\$ 687,381,305	\$ 271,846,881	\$ 19,899,062	\$ 5,377,790	\$ 25,276,852
37	1,153,788,363	\$ 673,783,238	\$ 266,469,091	\$ 19,455,873	\$ 5,251,813	\$ 24,707,686
38	1,153,788,363	\$ 660,503,712	\$ 261,217,278	\$ 19,421,375	\$ 5,286,311	\$ 24,707,686
39	1,153,788,363	\$ 647,136,954	\$ 255,930,968	\$ 19,386,650	\$ 5,321,036	\$ 24,707,686
40	1,153,788,363	\$ 633,682,393	\$ 250,609,932	\$ 19,351,697	\$ 5,355,989	\$ 24,707,686
41	1,153,788,363	\$ 620,139,451	\$ 245,253,943	\$ 19,316,514	\$ 5,391,171	\$ 24,707,686
42	1,153,788,363	\$ 606,507,549	\$ 239,862,772	\$ 19,281,101	\$ 5,426,585	\$ 24,707,686
43	1,153,788,363	\$ 592,786,100	\$ 234,436,187	\$ 19,245,455	\$ 5,462,231	\$ 24,707,686
44	1,153,788,363	\$ 578,974,518	\$ 228,973,956	\$ 19,209,574	\$ 5,498,111	\$ 24,707,686
45	1,153,788,363	\$ 565,072,210	\$ 223,475,845	\$ 19,173,458	\$ 5,534,228	\$ 24,707,686
46	1,153,788,363	\$ 551,078,581	\$ 217,941,617	\$ 19,137,105	\$ 5,570,581	\$ 24,707,686
47	1,153,788,363	\$ 536,993,030	\$ 212,371,036	\$ 19,100,513	\$ 5,607,173	\$ 24,707,686
48	1,153,788,363	\$ 522,814,953	\$ 206,763,863	\$ 19,063,680	\$ 5,644,005	\$ 24,707,686
49	1,173,544,032	\$ 508,543,744	\$ 201,119,858	\$ 18,525,809	\$ 5,483,024	\$ 24,008,833
50	1,173,544,032	\$ 494,679,585	\$ 195,636,834	\$ 18,489,792	\$ 5,519,041	\$ 24,008,833
51	1,173,544,032	\$ 480,724,356	\$ 190,117,793	\$ 18,453,539	\$ 5,555,295	\$ 24,008,833
52	1,173,544,032	\$ 466,677,457	\$ 184,562,498	\$ 18,417,047	\$ 5,591,786	\$ 24,008,833
53	1,173,544,032	\$ 452,538,287	\$ 178,970,712	\$ 18,380,316	\$ 5,628,518	\$ 24,008,833
54	1,173,544,032	\$ 438,306,239	\$ 173,342,194	\$ 18,343,343	\$ 5,665,490	\$ 24,008,833
55	1,173,544,032	\$ 423,980,703	\$ 167,676,704	\$ 18,306,127	\$ 5,702,706	\$ 24,008,833
56	1,173,544,032	\$ 409,561,065	\$ 161,973,998	\$ 18,268,667	\$ 5,740,166	\$ 24,008,833
57	1,173,544,032	\$ 395,046,708	\$ 156,233,832	\$ 18,230,961	\$ 5,777,872	\$ 24,008,833
58	1,173,544,032	\$ 380,437,008	\$ 150,455,960	\$ 18,193,007	\$ 5,815,826	\$ 24,008,833
59	1,173,544,032	\$ 365,731,340	\$ 144,640,134	\$ 18,154,804	\$ 5,854,029	\$ 24,008,833
60	1,173,544,032	\$ 350,929,073	\$ 138,786,105	\$ 18,116,350	\$ 5,892,483	\$ 24,008,833
61	1,194,296,868	\$ 336,029,572	\$ 132,893,622	\$ 17,481,898	\$ 5,695,583	\$ 23,177,481
62	1,194,296,868	\$ 321,627,946	\$ 127,198,039	\$ 17,444,484	\$ 5,732,966	\$ 23,177,481
63	1,194,296,868	\$ 307,131,718	\$ 121,465,043	\$ 17,406,825	\$ 5,770,655	\$ 23,177,481
64	1,194,296,868	\$ 292,540,267	\$ 115,694,387	\$ 17,368,919	\$ 5,808,562	\$ 23,177,481
65	1,194,296,868	\$ 277,852,967	\$ 109,885,826	\$ 17,330,764	\$ 5,846,717	\$ 23,177,481
66	1,194,296,868	\$ 263,069,189	\$ 104,039,109	\$ 17,292,358	\$ 5,885,123	\$ 23,177,481
67	1,194,296,868	\$ 248,188,299	\$ 98,153,986	\$ 17,253,699	\$ 5,923,781	\$ 23,177,481
68	1,194,296,868	\$ 233,209,659	\$ 92,230,204	\$ 17,214,787	\$ 5,962,694	\$ 23,177,481
69	1,194,296,868	\$ 218,132,627	\$ 86,267,511	\$ 17,175,619	\$ 6,001,861	\$ 23,177,481
70	1,194,296,868	\$ 202,956,557	\$ 80,265,650	\$ 17,136,194	\$ 6,041,287	\$ 23,177,481
71	1,194,296,868	\$ 187,690,798	\$ 74,224,363	\$ 17,096,510	\$ 6,080,971	\$ 23,177,481
72	1,194,296,868	\$ 172,304,695	\$ 68,143,392	\$ 17,056,565	\$ 6,120,915	\$ 23,177,481
73	1,215,630,037	\$ 156,827,590	\$ 62,022,477	\$ 16,147,131	\$ 5,817,359	\$ 21,964,490
74	1,215,630,037	\$ 142,118,045	\$ 56,205,118	\$ 16,108,918	\$ 5,855,572	\$ 21,964,490
75	1,215,630,037	\$ 127,311,876	\$ 50,349,546	\$ 16,070,453	\$ 5,894,036	\$ 21,964,490
76	1,215,630,037	\$ 112,408,448	\$ 44,455,509	\$ 16,031,737	\$ 5,932,753	\$ 21,964,490
77	1,215,630,037	\$ 97,407,123	\$ 38,522,756	\$ 15,992,765	\$ 5,971,724	\$ 21,964,490
78	1,215,630,037	\$ 82,307,256	\$ 32,551,032	\$ 15,953,538	\$ 6,010,952	\$ 21,964,490
79	1,215,630,037	\$ 67,108,201	\$ 26,540,080	\$ 15,914,053	\$ 6,050,436	\$ 21,964,490
80	1,215,630,037	\$ 51,809,306	\$ 20,489,644	\$ 15,874,309	\$ 6,090,181	\$ 21,964,490
81	1,215,630,037	\$ 36,409,915	\$ 14,399,463	\$ 15,834,304	\$ 6,130,186	\$ 21,964,490
82	1,215,630,037	\$ 20,909,369	\$ 8,269,277	\$ 15,794,036	\$ 6,170,454	\$ 21,964,490
83	1,215,630,037	\$ 5,307,002	\$ 2,098,823	\$ 15,753,503	\$ 6,210,987	\$ 21,964,490

APPENDIX G REVISION -- METHOD B

**ACCOUNTING PROTOCOLS
FOR DUQUESNE GENERATION AUCTION**

As required by the Commission, the proceeds from the auction conducted pursuant to this Auction Plan will be used to determine the stranded costs of Duquesne for the Company's generation. This section will discuss the accounting protocols necessary to establish a market-based stranded cost valuation for generation from the auction proceeds and to reconcile that actual valuation with the collection of interim CTC charges¹ based on the generation credits from Duquesne's Pilot.

A. Net Auction Proceeds

The net auction proceeds ("Net Auction Proceeds") from the transfer of all divested Utility Assets² shall be defined as the sum of the sales prices paid by

¹ The Commission's August 13, 1998 Opinion and Order on Duquesne's compliance filing (the "Compliance Order") adopted the Company's proposal for the interim CTC charges. Compliance Order at 12.

² Utility Assets do not include assets that have been excluded by the Commission in its determination of stranded costs (*i.e.*, the non-rate base portions of the Brunot Island generating units and the Phillips generating unit). Proceeds from these excluded assets will not be considered for purposes of determining the Net Auction Proceeds. All other generating assets to be auctioned by Duquesne (including the assets exchanged with FirstEnergy Corporation ("FEC")) are included for purposes of determining stranded costs and are considered to be Utility Assets for purposes of the auction. Pursuant to its Agreement in Principle (the "Swap Agreement") to exchange certain generating asset with FEC, as filed with the Commission on October 14, 1998, Duquesne will auction the wholly-owned fossil generating assets received from FEC (the "FEC Assets") rather than the partial interests in
(continued...)

the new owners less the transaction costs.³ Transaction costs shall include all reasonable incremental expenditures that are assignable to the divested Utility Assets ("Transaction Costs"), including but not limited to:

- (i) The costs of developing and implementing this Auction Plan (e.g., fees of outside experts, including investment bankers, engineering and environmental consultants, economic and financial consultants and legal counsel, and any expenditures associated with a potential transfer of the Beaver Valley Unit 2 lease); including the costs of implementing the Swap Agreement with FEC, i.e., the costs of terminating the Beaver Valley II lease so as to permit the transfer of Beaver Valley II to FEC);

² (...continued)
fossil and nuclear generating assets transferred to FEC (the "Transferred Assets"). The sum of the sales prices paid by the new owners for the FEC Assets will be included in the Net Auction Proceeds. The Transferred Assets will not be auctioned and thus not included in the Net Auction Proceeds. However, the book values used in the Commission's administrative determination of stranded costs as of January 1, 1999 will still be used for finally determining stranded costs based on the offset credits to stranded costs and to deferred taxes derived from the market values determined in the auction. In summary, book values are based on Duquesne's original generation assets and market values are based on the generation assets auctioned.

³ The sales price shall be deemed to be zero for any Utility Asset for which a transfer is not completed, whether because no qualifying bids were received or because conditions precedent to such a transfer were not satisfied. In the event Duquesne receives a qualifying "negative bid" (See Section II.D., E. Qualifying Bids) that Duquesne is prepared to accept, the negative bid will be used to reduce the sum of the other non-negative sales prices for Utility Assets in determining the Net Auction Proceeds.

- (ii) Incremental O & M costs (e.g., associated with the demarcation of facilities at Utility Assets), employee costs, environmental costs and any tax implications relating to this Auction Plan other than those described below under After-tax Auction Proceeds;
- (iii) Incremental divestiture-related capital expenditures (e.g., associated with the demarcation of facilities at Utility Assets) necessary to complete the transfers to new owners; and
- (iv) The present value of any severance costs payable to employees at the Utility Assets divested pursuant to this Auction Plan.

As an illustrative example assume that the sum of the sales prices for all Utility Assets is equal to ~~\$500~~ \$590 million and that Transaction Costs total ~~\$25~~ \$115 million, including: \$20 million for fees of outside experts; \$90 million for the termination of the Beaver Valley II lease; \$3 million of incremental O & M, employee and environmental costs; and \$2 ~~of~~ million of incremental divestiture-related capital expenditures. In that event, the Net Auction Proceeds would equal \$475 million or the sum of the sales prices (~~\$500~~\$590 million) less the Transaction Costs (~~\$25~~\$115 million).

B. After-tax Auction Proceeds

The after-tax gains or losses on the transfer of ~~divested~~ the auctioned assets will be reflected in determining the after-tax auction proceeds ("After-tax Auction Proceeds") from the sale of Utility Assets under this Auction Plan. The After-tax Auction Proceeds shall be defined as the Net Auction Proceeds less current taxes payable ("Current Taxes") as a result of the transfers of the Utility Assets divested.

Current Taxes are defined as all Pennsylvania or Ohio, and any other applicable gross receipts, excess dividends, property transfer and sales taxes (including applicable surcharges); plus, the difference between the Net Auction Proceeds and the remaining tax basis⁴ of the Utility Assets divested at the date of transfer, multiplied by the then-current combined federal-state income tax rate (currently 41.4935%).

Again, as an illustrative example, in addition to the above assumptions assume the tax basis of ~~assets~~ Utility Assets divested is \$180 million on the date of closing, the tax rate is 41.4935% on the date of closing and no other Pennsylvania or Ohio taxes are applicable. In that event, the After-tax Auction Proceeds will

⁴ The net tax effect of the implementing the Swap Agreement and auctioning the FEC Assets and Duquesne's remaining interest in Cheswick, Elrama, and the rate-based portion of Brunot Island, is that the tax basis of all auctioned assets will effectively be equal to the tax basis of Duquesne's generating assets as if the Swap Agreement had not been implemented. For purposes of the illustrative example, all references to the "tax basis of Utility Assets" divested are intended to refer to the tax basis of Duquesne's generating assets, including the Transferred Assets, and excluding the FEC Assets.

equal \$352.59 million, or Net Auction Proceeds (\$475.00 million) less Current Taxes (\$122.41 million) as shown in the table below.

	(\$000)
Sum of Sales Prices	500,000 <u>590,000</u>
(Transaction Costs)	<u>(25,000)</u> <u>(115,000)</u>
Net Auction Proceeds	475,000
(Tax Basis)	<u>(180,000)</u>
Taxable Gain	295,000
Current Taxes @ 41.4935%	<u>(122,406)</u>
After-tax Auction Proceeds	352,594

C. Stand Alone Base Case

The Restructuring Order includes a determination of stranded costs based on an administrative determination of the after-tax market value of Duquesne's generating assets as of year-end 1998. ~~This total after-tax value is based on the Commission's acceptance of the OCA's calculation of a NPV of \$99.4 million from a margin analysis of Duquesne's owned units as reproduced in Appendix G (at 1a).~~ The OCA proposed certain adjustments to the results of the margin analysis, which were rejected in part and accepted in part by the Commission. The net effect of all the Commission's accepted adjustments to the OCA's \$99.4 million margin NPV was to increase this value equal to \$110.95 million.

The Stand Alone Base Case for Duquesne is attached as Appendix G (at ~~2a~~ 1a). This table presents a revised Appendix B from the Restructuring Order, with an additional column to show the corrections to the Commission's deferred tax calculation from the Compliance Order.⁵ A copy of the Stranded Cost Allowance from the Compliance Order is reproduced in Appendix G (at ~~3a~~ 2a).

Three changes are necessary to properly reflect the administrative determination of stranded costs for Duquesne on a stand alone basis. First, the Compliance Order Stranded Cost Allowance in Appendix G (at ~~3a~~ 2a) includes the generation Merger Savings of \$152.28 million. In a non-merger scenario, no generation merger savings are obtainable. Second, pursuant to the Compliance Order the Deferred Fuel Cost Regulatory Asset should be shown at its updated value of \$25.00 million because Duquesne has been denied a roll-in of its ECR at the higher value reflected in the original compliance filing. Third, the Commission's calculation of \$493 million for deferred taxes is in error, and must be restated as \$653 million on a stand alone basis, most of which is attributable to the foregone merger synergies. The corrections to the deferred tax calculation are summarized below:

⁵ The Compliance Order was issued on August 13th and contains certain calculational errors. Duquesne corrected those errors in its revised compliance filing, and a description of the main corrections is summarized here.

Deferred Tax Item	(\$Million)
a. Generating Plant Book ⁶	372.46
Corrected Value	<u>411.34</u>
a. Increase	38.88
b. Merger Savings	(107.99)
Corrected Value	<u>0.00</u>
b. Increase	107.99
c. Deferred Fuel Costs	4.77
Corrected Value	<u>17.73</u>
c. Increase	12.96
Total Increase (a. + b. + c.)	159.83
PA Jurisdictional (at 99.9%)	159.67

D. Reconciliation with Stand Alone Base Case

To reconcile the stranded costs resulting from the actual market value (i.e., the After-tax Auction Proceeds) with the Stand Alone Base Case resulting from the Commission's year-end 1998 administratively determined value of \$110.95

⁶ For purposes of this summary calculation, the Restructuring Order's understatement of deferred tax balances by \$38.88 million has been attributed solely to Generating Plan Book. Duquesne took exception to this computational error in the Merger Compliance Filing. Page 2, note 2 clearly states that "Appendix A [to the Compliance Filing] also provides a description and break-down of the correct deferred tax balance associated with the Commission's administrative determination of stranded costs, while excluding the deferred taxes associated with disallowed cost items, including BI and Phillips. The Final Order does not explain how the deferred tax balance contained in Appendix D was derived, but it is not correct." The relevant pages of Appendix A to the Compliance Filing are reproduced here in Appendix G (at 3a-3c). The difference between the Commission's undocumented \$493.345 million deferred tax balance and Duquesne's detailed calculation of \$532.188 million (Appendix G at 3b) is \$38.88 million, as adjusted for the 99.9% PA jurisdictional factor.

million will require an adjustment to account for the timing of the auction.⁷ Continuing with the example discussed above, assume the asset sales close at year-end 1999 and the After-tax Auction Proceeds (as calculated above) are \$352.59 million. This amount cannot be reconciled directly (i.e., by subtraction) with the Commission's \$110.95 million administratively determined value because of the timing difference.

However, the \$352.59 million value can be present valued as a future OCA's margin analysis can be moved forward to year-end 1999 to calculate the comparable present value by applying the OCA's NPV of margin methodology from that date forward.

~~Appendix G (at 5a) contains a summary table showing the values that would be obtained from Mr. Kahal's margin analysis if the margins were recalculated at the same 6.88% discount rate at year-end 1999 and year-end 2000. This table is based on the workpapers filed with the OCA direct testimony, including a spreadsheet (Margin_2.xls) prepared by OCA witness Kahal. The first column replicates the results of the OCA analysis as filed (at year-end 1998). The second and third columns show the recalculation of the margin results adjusted for timing. The OCA's after-tax margin NPV increases to \$126.3 million and \$164.5 million at year-end 1999 and 2000 respectively. The difference from the cash flow (at the Commission's~~

⁷ The Commission recognizes that the divestiture may not be accomplished by January 1, 1999 and requires that the actual stranded utility generation value be reconciled. See Restructuring Order at 81-82.

approved⁸ after-tax discount rate of 7.29%) and we can thereby determine the after-tax market value as of January 1, 1999. The resulting year-end 1998 value of \$99.4 is \$328.64 million (\$352.59 is shown at the bottom of the table.

The future NPVs are greater than the year-end 1998 value by \$27.0 million and \$65.1 million respectively. These values have been calculated directly from Margin_2.xls. A printout of pages from Margin_2.xls is attached as Appendix G (at 6a-6d), and shows the annual after-tax margin summaries for each Duquesne plant as calculated by Mr. Kahal. The year-end 1998 margin NPVs for each unit appear at the far right of the second page of each table following the year 2026. The calculated OCA values are used by Mr. Kahal to derive the margins shown on Schedule MIK-1, December 1997 Update, Page 2 of 3, 1.0729.

Continuing with the example discussed above, Duquesne will adjust Appendix G (at 4a) shows the changes to the Stand Alone Base Case administrative that will result from calculating the offset credits at January 1, 1999. First, the administratively determined market value of \$110.95 million upward by the \$27.0 million difference shown in Appendix G (at 5a) and then subtract this adjusted value from the After-tax Auction Proceeds to determine the offsetting credit to ratepayers is adjusted by applying the offset credit ("Market Value Offset Credit") of \$217.69

⁸ Restructuring Order at 192.

million against stranded costs.⁹ An equivalent credit to the recoverable deferred taxes is calculated by multiplying the Market Value Offset Credit by the fraction (Tax Rate/(1-Tax Rate)). At a statutory tax rate of 41.4935% this will provide a deferred tax credit ("Deferred Tax Offset Credit") equal to approximately \$0.71 for every dollar of Market Value Offset Credit. Continuing with our example, the derivation of these credits is shown in the table below.

	(\$000)
<u>Future After-Tax Market Value</u>	<u>352,594</u>
<u>January 1, 1999 Market Value (at 7.29%)</u>	<u>328,637</u>
<u>January 1, 1999 Administrative Value</u>	<u>110,950</u>
Adjustment for OCA Margin 27,000	
Future Administrative Value 137,950	
After-tax Auction Proceeds (352,594)	
Market Value Offset Credit	(214,644) <u>(217,687)</u>
Deferred Tax Offset Credit (@ \$.71 per \$)	(152,228) <u>(154,386)</u>

In addition to the offset credits shown in Appendix G (at 4a), if the auction proceeds are reconciled on an after-tax basis, as illustrated above, then

⁹ This assumes the closing occurs at year-end 1999. An earlier or later closing would require a different adjustment. The future value of \$352.59 million would be discounted for the actual number of days between January 1, 1999 and the date(s) of closing at an annual rate of 7.29%.

Duquesne does not also need to recover the FAS 109 Regulatory Asset balance of \$179.00 million (and associated deferred tax balance of \$57.48 million). Thus, as illustrated in Appendix G (at 4a) the FAS 109 Regulatory Asset (and associated deferred tax balance) should be eliminated from otherwise recoverable stranded costs if the Company's proposal to account for auction proceeds on a net of tax basis is accepted. Accounting for both the offset credits and the elimination of the FAS 109 Regulatory Asset, stranded costs are reduced by a total of \$396.69 million and the associated deferred tax balances are reduced by a total of \$211.87 million¹⁰.

E. Reconciliation with Interim CTC Revenues

The Restructuring Order provides if Duquesne divests its generating assets through an auction process, that beginning in 1999 an interim CTC may be charged to shopping customers based on the Pilot credits. Duquesne filed class specific residual CTC tariffs based on the Pilot credits in its Stand Alone Compliance Filing. The resulting Company average 1999 CTCs are approximately 2.7 cents (excluding GRT). The CTC revenues collected prior to completion of the auction will be allocable to recovery of stranded costs, return on the unamortized balance of stranded costs, and amortization of deferred taxes. However, the magnitude of the

¹⁰ After application of the 99.9% PA jurisdictional allocation, the actual reduction in stranded costs is \$396.29 million and the reduction in the associated deferred tax balance is \$211.65 million.

Market Value Offset Credit and the Deferred Tax Offset Credit will not be known until the auction is completed, and the reconciliation will be done at that time.

~~The first step in the reconciliation process is to calculate a pro-forma set of monthly CTC revenue requirements (in the form of Appendix C of the Restructuring Order) beginning in 1999 based on the Stand Alone Base Case. However, the Compliance Order required Duquesne to calculate CTC revenue requirements that would produce average shopping credits equal to those produced in the Restructuring Order.~~

~~Accordingly, within each year, the monthly pro-forma CTC revenue requirements provide for a levelized recovery of stranded costs at a fully grossed-up return of 11% and a levelized amortization of the associated deferred tax balances. However, the annual total CTC revenue requirement is constrained to produce an average shopping credit equal to 4.00 cents/kWh in 1999, 4.22 cents/kWh in 2000 and so forth, consistent with the shopping credits in the Restructuring Order.~~

Continuing with the example discussed above, Appendix G (at 5a shows 7a) shows the CTC revenue requirements under the Stand Alone Base Case in 1999 and 2000. In 1999, the total monthly revenue requirements pro-formed are \$27,000,000 consisting of \$22,847,259 of blended CTC recovery and return and \$4,152,741 of deferred tax amortization.

The 1999 pro-forma CTC revenue requirements under the Stand Alone Base Case are less than the CTC revenues that will be collected under the Pilot credit tariffs,

assuming the forecast level of sales during the interim period is realized. At ~~1,098,149,355~~ 1,043,241,887 kWh/month, the monthly 1999 CTC revenues recovered under the Pilot tariffs will be \$28,424,169. The allocation of the Pilot CTC revenues to return and amortization is \$29,815,194.

~~Appendix G (at 8a) shows the reconciliation between the pro-forma CTC revenue requirements (based on the Stand Alone Base Case) 99.9% jurisdictional 1999 CTC beginning balance of \$1,105.66 million and the 1999 interim CTC revenues collected (assuming the forecast sales under the Pilot Credit CTCs are realized). The realized revenues are allocated between CTC recovery and return (84.62% of CTC revenue) and deferred tax amortization (15.38% of CTC revenue). The 84.62% portion of realized 1999 DT beginning balance of \$441.36 million.~~

The amount of Pilot CTC revenues allocated to CTC recovery and return is further decomposed into the recovery of and return on the CTC balance of \$1,502 million. return is based on the Commission's allowed 11% CTC return as calculated monthly on the unamortized CTC balance. The amount of Pilot CTC revenues allocated to recovery of the stranded cost balance and to the amortization of the deferred tax balance is determined such that the reduction in each balance is proportionate. Thus, during the interim Pilot CTC period, the proportion of total dollar value of recovery of stranded costs (calculated as a percentage of the 1999 beginning stranded cost balance) will be equal to the proportion of total dollar value

of amortization of deferred taxes (calculated as a percentage of the 1999 beginning deferred tax balance). The sum of the three components so calculated (return, recovery and amortization) will be equal to the total dollar value of Pilot CTC revenues collected.

Based on the 1999 CTC revenue collections (under the CTC Pilot credit tariffs) and the above allocation between the stranded cost and deferred tax components, the 1999 Ending Stranded Cost Balance will be \$1,375,380,051 \$943,026,821 and the 1999 Ending Deferred Tax Balance will be \$376,438,350 \$597,983,204. ~~The Market Value Offset Credit of \$214.6 million and the Deferred Tax Offset Credit of \$152.2 million will be applied against these unamortized balances as shown in the table below:~~

(\$000)

~~1999 Ending CTC Balance 1,375,380~~

~~Market Value Offset Credit (214,644)~~

~~2000 Beginning CTC Balance 1,160,736~~

~~1999 Ending DT Balance 597,983~~

~~Deferred Tax Offset Credit (152,228)~~

2000 Beginning DT Balance 445,755

F. Post-Auction CTC Design

Based on the above reconciliation of the year 2000 starting balances (after applying the Market Value Offset Credit and the Deferred Tax Offset Credit), the new balances can be reamortized using the same methodology as approved in the Compliance Order.¹¹

Appendix G (at 9a) ~~sets out 6a)~~ shows the CTC revenue requirements¹² ~~assuming the Market Value Offset Credit and the Deferred Tax Offset Credit are applied at the beginning of 2000. Again, using the CTC Revenue Requirements from the Compliance Order for illustrative purposes in 2000 and later that will result from targeting the Commission's approved Company average shopping credits set out in the Restructuring Order. Appendix G (at 7a) sets out the monthly equiva-~~

¹¹ The Compliance Order (at 15-16) requires Duquesne to calculate CTC revenue requirements that would produce average shopping credits equal to those contained in the Restructuring Order. The resulting Company-wide CTC revenue requirements would be allocated to rate classes based on the production cost allocation methodology set out in Duquesne's compliance filing. Similarly, the actual reconciliation of the Pilot CTC revenues for each class would be based on the allocation of the total *stranded* cost and deferred tax balances at the beginning of 1999 using the production cost allocators. The annual reconciliation of class CTC revenues to class CTC revenue requirements, would be performed on a class specific basis with a recalculation of monthly recovery, return and deferred tax amortization based on actual sales volumes of that class. Within each year, the monthly pro-forma CTC revenue requirements provide for a recovery of stranded costs at a fully grossed-up return of 11% and a proportionate amortization of the associated deferred tax balance. Any underrecovery or overrecovery resulting from differences between forecast and actual sales for a particular class, would result in a lengthening or shortening of the recovery period for such class.

¹² Originally filed November 5, 1998 as part of Duquesne's revised compliance filing.

lent of these CTC revenue requirements (i.e., for 2000 the monthly CTC revenue requirement is \$309,939,205 divided by 12, or \$25,828,267. Appendix G (at 6a) shows how the remaining CTC and deferred tax balances are amortized over the remaining transition period. In each year the percentage amortization of the remaining CTC asset and remaining deferred tax balance are equivalent. Using the shopping credits from the Commission's Restructuring Order and the sales forecast and T&D rates from the most recent Company compliance filing, the CTC and Deferred Tax balances are fully amortized by year-end 2006-2005.

----- COMPARISON OF FOOTNOTES -----

-FOOTNOTE 1-

The Commission's August 13, 1998 Opinion and Order on Duquesne's compliance filing (the "Compliance Order") adopted the Company's proposal for the interim CTC charges. Compliance Order at 12.

-FOOTNOTE 2-

Utility Assets ~~are those assets divested by Duquesne which have had their book values included for purposes of determining stranded costs. Assets~~ do not include assets that have been excluded by the Commission in determining its determination of stranded costs (e.g. (i.e., the non-rate base portions of the Brunot Island generating units) are not and the Phillips generating unit). Proceeds from these excluded assets will not be considered as Utility Assets for purposes of determining the Net Auction Proceeds. All other generating assets to be auctioned by Duquesne (including the assets exchanged with FirstEnergy Corporation ("FEC")) are included for purposes of determining stranded costs and are considered to be Utility Assets for purposes of the auction. Pursuant to its Agreement in Principle (the "Swap Agreement") to exchange certain generating asset with FEC, as filed with the Commission on

October 14, 1998, Duquesne will auction the wholly-owned fossil generating assets received from FEC (the "FEC Assets") rather than the partial interests in fossil and nuclear generating assets transferred to FEC (the "Transferred Assets"). The sum of the sales prices paid by the new owners for the FEC Assets will be included in the Net Auction Proceeds. The Transferred Assets will not be auctioned and thus not included in the Net Auction Proceeds. However, the book values used in the Commission's administrative determination of stranded costs as of January 1, 1999 will still be used for finally determining stranded costs based on the offset credits to stranded costs and to deferred taxes derived from the market values determined in the auction. In summary, book values are based on Duquesne's original generation assets and market values are based on the generation assets auctioned.

-FOOTNOTE 3-

The sales price shall be deemed to be zero for any Utility Asset for which a transfer is not completed, whether because no qualifying bids were received or because conditions precedent to such a transfer were not satisfied. In the event Duquesne receives a qualifying "negative bid" (See Section II.D., E. Qualifying Bids) that Duquesne is prepared to accept, the negative bid will be used to reduce the sum of the other non-negative sales prices for Utility Assets in determining the Net Auction Proceeds.

~~-FOOTNOTE 4-~~

~~The total includes a negative qualifying bid of \$15.0 million for Perry that includes a market determination of an additional \$5.0 million of required nuclear decommissioning funding in excess of that authorized for recovery by the Commission for Perry. The sum of the sales prices for all other assets is \$515 million, resulting in a total sum net tax effect of the implementing the Swap Agreement and auctioning the FEC Assets and Duquesne's remaining interest in Cheswick, Elrama, and the rate-based portion of Brunot Island, is that the tax basis of all auctioned assets will effectively be equal to the tax basis of Duquesne's generating assets as if the Swap Agreement had not been implemented. For purposes \$500 million.~~

~~-FOOTNOTE 5-~~

~~Schedule MIK-1, December 1997 Update, Page 2 of the illustrative example, all references to the "tax basis of Utility Assets" divested are intended to refer to the tax basis of Duquesne's generating assets, including the Transferred Assets, and excluding the FEC Assets. 3.~~

~~-FOOTNOTE 6-~~

~~Restructuring Order at 123, 128.~~

-FOOTNOTE 7 5-

The Compliance Order was issued on August 13th and contains certain calculational errors. Duquesne ~~will correct~~ corrected those errors in its revised compliance filing. ~~The Stand Alone Base Case in Appendix G (at 2a) reflects the~~, and a description of the main corrections ~~that Duquesne will seek to the Compliance Order~~ is summarized here.

-FOOTNOTE 8 6-

For purposes of this summary calculation, the Restructuring Order's understatement of deferred tax balances by \$38.88 million has been attributed solely to Generating Plan Book. Duquesne took exception to this computational error in the Merger Compliance Filing. Page 2, note 2 clearly states that "Appendix A [to the Compliance Filing] also provides a description and break-down of the correct deferred tax balance associated with the Commission's administrative determination of stranded costs, while excluding the deferred taxes associated with disallowed cost items, including BI and Phillips. The Final Order does not explain how the deferred tax balance contained in Appendix D was derived, but it is not correct." The relevant pages of Appendix A to the Compliance Filing are reproduced here in Appendix G (at ~~4a-4e~~) 3a-3c). The difference between the Commission's undocumented \$493.345 million deferred tax balance and Duquesne's detailed calculation of \$532.188 million

(Appendix G at 4b) 3b) is \$38.88 million, as adjusted for the 99.9% PA jurisdictional factor.

~~-FOOTNOTE 9~~ 7-

The Commission recognizes that the divestiture may not be accomplished by January 1, 1999 and requires that the actual stranded utility generation value be reconciled.

See Restructuring Order at 81-82.

~~-FOOTNOTE 8-~~

Restructuring Order at 192.

~~-FOOTNOTE 10~~ 9-

This assumes the closing occurs at year-end 1999. An earlier or later closing would require a different adjustment. The ~~values at year-end 1998, 1999 and 2000 can be used to interpolate the adjustment if the closing of the auction occurs earlier in calendar~~ future value of \$352.59 million would be discounted for the actual number of days between January 1, 1999 and or later in calendar year 2000.

~~-FOOTNOTE 11-~~

~~Under the Stand Alone Base Case a 1999 beginning stranded cost balance date(s) of \$1,502 closing at an annual rate of 7.29%.~~

~~-FOOTNOTE 10-~~

~~After application of the 99.9% PA jurisdictional allocation, the actual reduction in stranded costs is \$396.29 million and the reduction in the associated deferred tax balance of \$653 is \$211.65 million must be recovered through the CTC.~~

~~-FOOTNOTE 12-~~

~~Compliance Order at 15-16.~~

~~-FOOTNOTE 13 11-~~

~~The Compliance Order provides that Duquesne's (at 15-16) requires Duquesne to calculate CTC revenue requirements that would produce average CTCs must be recalculated, adjusting for the new treatment of deferred taxes, the disallowance of the ECR roll-in and the recalculation of T&D rates, in order to produce the same shopping credits as equal to those contained in the Restructuring Order. This may require an extension of the recovery period and will result in different year-to-year CTC revenue requirements.~~

~~-FOOTNOTE 14-~~

~~For purposes of the example, we have assumed the total CTC Revenue Requirements are constrained to the values set out in the Commission Shopping Credit table to the Compliance Order. The resulting Company-wide actual constraints will be determined in Duquesne's next Compliance Filing.~~

~~-FOOTNOTE 15-~~

~~After application of the credits, the actual CTC revenue requirements would be recalculated to produce average shopping credits on a company-wide basis equal to those in the Restructuring Order. The resulting annual CTC revenue requirements would be allocated to rate classes based on the production cost allocation methodology set out in Duquesne's Duquesne's compliance filing. Similarly, the actual reconciliation of the Pilot CTC revenues for each class would be based on the allocation of the total stranded cost and deferred tax balances at the beginning of 1999 using the production cost allocators. The annual reconciliation of class CTC revenues to class CTC revenue requirements(~~as determined after the application of the above credits~~), would be performed on a class specific basis with a recalculation of monthly recovery, return and deferred tax amortization based on actual sales volumes of that class. Within each year, the monthly pro-forma CTC revenue requirements provide for a recovery of stranded costs at a fully grossed-up return of~~

11% and a proportionate amortization of the associated deferred tax balance. Any underrecovery or overrecovery resulting from differences between forecast and actual sales for a particular class, would result in a lengthening or shortening of the recovery period for such class.

-FOOTNOTE 12-

Originally filed November 5, 1998 as part of Duquesne's revised compliance filing.

----- COMPARISON OF FOOTERS -----

-FOOTER 1-

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**Stranded Cost Allowance
with Associated Deferred Taxes
(\$Millions)**

Stand Alone Base Case

<u>Category/Item:</u>	<u>Deferred Taxes</u>	<u>Amount</u>
Duquesne Light Restructuring		
Book Value:		
Generating Plant Book Value	\$ 411.34	\$ 852.03
Beaver Valley 2 Lease PV	\$ 213.01	\$ 300.35
M&S Fuel Related Sunk Costs	-	-
Working Capital	-	\$ 61.53
Costs Independent of Operation	-	-
Generation Market Value	\$ (78.69)	\$ (110.95)
Merger Savings	\$ -	\$ -
Total Stranded Generation:	\$ 545.66	\$ 1,102.96
Decommissioning:		
Nuclear Decommissioning	-	\$ 42.96
Fossil Decommissioning	-	-
Total Decommissioning	\$ -	\$ 42.96
Regulatory Assets:		
FAS 109 (including Plant reversal)	\$ 57.48	\$ 179.00
Post '05 Unamortized Debt Costs	\$ 10.67	\$ 18.67
Pre '06 Unamortized Debt Costs	\$ 6.82	\$ 9.61
Deferred Rate Synch. (Early Window)	\$ 1.87	\$ 23.50
Deferred Employee Costs	-	\$ 14.24
Deferred Nuclear Maintenance	\$ 1.35	\$ 1.90
US DOE Decommissioning	\$ 2.33	\$ 3.25
Deferred Coal Costs	-	-
Deferred Caretaker Costs	-	-
Pre-Accrued Nuclear Outage	-	-
BV2 Training Costs	\$ 0.84	\$ 1.58
Low Level Radioactive Waste	-	\$ 2.27
Coal Cost Equalization	-	\$ 0.12
Transition Costs	\$ 7.51	\$ 10.59
SFAS 106 Deferral	\$ 1.40	\$ 1.97
Deferred Fuel Costs	\$ 17.73	\$ 25.00
Other Regulatory Assets	-	\$ 0.53
Consumer Education	-	\$ 10.00
Sale-Leaseback Tax Effect (Gain)	-	\$ 55.13
Deferred Rate Synch. Costs	-	-
BV2 Tax Effect	-	\$ 0.17
Total Regulatory Assets:	\$ 108.00	\$ 357.53
PA Jurisdictional % (1-FERC Allocation)	99.900%	99.900%
TOTAL STRANDED, STAND ALONE	\$ 653.012	\$ 1,501.948
WITH JURISDICTIONAL ALLOCATION		

**Stranded Cost Allowance
(\$Millions)**

Category/Item:	Amount
Duquesne Light Restructuring	
Book Value:	
Generating Plant Book Value	\$ 852.03
Beaver Valley 2 Lease PV	\$ 300.35
M&S Fuel Related Sunk Costs	-
Working Capital	\$ 81.53
Costs Independent of Operation	-
Generation Market Value	\$ (110.95)
Merger Savings	\$ (152.28)
Total Stranded Generation:	\$ 950.68
Decommissioning:	
Nuclear Decommissioning	\$ 42.98
Fossil Decommissioning	-
Total Decommissioning	\$ 42.98
Regulatory Assets:	
FAS 109 (including Plant reversal)	\$ 179.00
Post '05 Unamortized Debt Costs	\$ 18.87
Pre '08 Unamortized Debt Costs	\$ 9.61
Deferred Rate Synch. (Early Window)	\$ 23.50
Deferred Employee Costs	\$ 14.24
Deferred Nuclear Maintenance	\$ 1.90
US DOE Decommissioning	\$ 3.25
Deferred Coal Costs	-
Deferred Caretaker Costs	-
Pre-Accrued Nuclear Outage	-
BV2 Training Costs	\$ 1.58
Low Level Radioactive Waste	\$ 2.27
Coal Cost Equalization	\$ 0.12
Transition Costs	\$ 10.58
SFAS 106 Deferral	\$ 1.97
Deferred Fuel Costs	\$ 6.73
Other Regulatory Assets	\$ 0.53
Consumer Education	\$ 10.00
Sale-Leaseback Tax Effect (Gain)	\$ 55.13
Deferred Rate Synch. Costs	-
BV2 Tax Effect	\$ 0.17
Total Regulatory Assets:	\$ 339.26
PA Jurisdictional % (1-FERC Allocation)	99.900%
TOTAL STRANDED, WITH MERGER AND JURISDICTIONAL ALLOCATION	\$ 1,331.667

Discussion re: Deferred Taxes in PaPUC Decision

The May 29, 1998 Opinion and Order of the Commission determined and allowed recovery of stranded costs for Duquesne in the amount of \$1,331,567,100 in the event the merger with Allegheny is consummated. Attachment B to the Order summarizes the individual components of stranded costs (net of tax) allowed by the Commission under the merger case. Attachment D to the Order identifies a Deferred Tax Principal balance of \$493,344,701 associated with this stranded cost determination. The Order contains no equivalent breakout of the individual components of the deferred tax total comparable to that of stranded costs presented in Attachment B.

The April 13, 1998 Exceptions of Duquesne to the ALJ Recommended Decision included an Appendix B that presented a Revised Exhibit No. DJC-10 summarizing the stranded cost recommendations of Duquesne, the OCA and the ALJ. Appendix B presented both Gross and Net stranded cost components, and the deferred tax balances associated with each component.

Duquesne believes the Commission has referred to the component breakout presented in Appendix B to Duquesne's Exceptions in deriving the deferred tax total presented in Attachment D to the Order. However, the Company has been unable to replicate the derivation of the Order's \$493,344,701 deferred tax balance.

The attached table "Stranded Cost Allowance with Associated Deferred Taxes" is based on Attachment B to the Commission's Order and Appendix B of Duquesne's Exceptions. The table presents an associated deferred tax balance for each component allowed by the Commission in the merger case. These balances are based on the deferred tax recommendations of the ALJ (for components allowed by the Order) as set out in Revised Exhibit No. DJC-10, except as otherwise shown in the Notes on Deferred Taxes below.

Notes on Deferred Taxes:

- 1) The balance of \$411.34 MM reflects an addition of \$2.56 MM (to the ALJ's balance of \$408.78 MM) for deferred taxes associated with the Warwick Mine plant balance, that was allowed by the Order, but not included in the ALJ's recommended decision. Note that deferred taxes associated with Brunot Island and Phillips were not included in the ALJ balance of \$408.92 MM. See Note ALJ-1, Appendix B, DLC Exceptions.
- 2) The Order determined a generation market value of \$110.95 MM, less than the \$286.03 MM value recommended by the ALJ. In Appendix B, the associated reduction in the deferred taxes associated with the ALJ's recommended market value is \$202.86 MM. Duquesne has calculated an imputed reduction of \$78.69 MM for the Order's market value based on a tax rate of 41.4935%.
- 3) The Order has adopted the OCA's recommended value for certain Regulatory Assets. The deferred tax balances reflect the OCA's values shown in Appendix B, DLC Exceptions.
- 4) The deferred taxes associated with the Deferred Fuel Costs reflect the Order's value of \$6.73 MM and have not been updated through May 29, 1998.

Stranded Cost Allowance
with Associated Deferred Taxes
(\$Millions)

Duquesne Light Restructuring		
<u>Category/Item:</u>	<u>Deferred Taxes</u>	<u>Amount</u>
Book Value:		
Generating Plant Book Value (1)	\$ 411.34	\$ 852.03
Beaver Valley 2 Lease PV	\$ 213.01	\$ 300.35
M&S Fuel Related Sunk Costs	-	-
Working Capital	-	\$ 61.53
Costs Independent of Operation	-	-
Generation Market Value (2)	\$ (78.69)	\$ (110.95)
Merger Savings	\$ (107.99)	\$ (152.28)
Total Stranded Generation:	\$ 437.67	\$ 950.68
Decommissioning:		
Nuclear Decommissioning	-	\$ 42.96
Fossil Decommissioning	-	-
Total Decommissioning	\$ -	\$ 42.96
Regulatory Assets:		
FAS 109 (including Plant reversal)	\$ 57.48	\$ 179.00
Post '05 Unamortized Debt Costs (3)	\$ 10.67	\$ 18.67
Pre '06 Unamortized Debt Costs (3)	\$ 6.82	\$ 9.61
Deferred Rate Synch. (Early Window)	\$ 1.87	\$ 23.50
Deferred Employee Costs	-	\$ 14.24
Deferred Nuclear Maintenance	\$ 1.35	\$ 1.90
US DOE Decommissioning	\$ 2.33	\$ 3.25
Deferred Coal Costs	-	-
Deferred Caretaker Costs	-	-
Pre-Accrued Nuclear Outage	-	-
BV2 Training Costs	\$ 0.84	\$ 1.58
Low Level Radioactive Waste	-	\$ 2.27
Coal Cost Equalization	-	\$ 0.12
Transition Costs	\$ 7.51	\$ 10.59
SFAS 106 Deferral (3)	\$ 1.40	\$ 1.97
Deferred Fuel Costs (4)	\$ 4.78	\$ 6.73
Other Regulatory Assets	-	\$ 0.53
Consumer Education	-	\$ 10.00
Sale-Leaseback Tax Effect (Gain)	-	\$ 55.13
Deferred Rate Synch. Costs	-	-
BV2 Tax Effect	-	\$ 0.17
Total Regulatory Assets:	\$ 95.05	\$ 339.26
PA Jurisdictional % (1-FERC Allocation)	99.900%	99.900%
TOTAL STRANDED, WITH MERGER AND JURISDICTIONAL ALLOCATION	\$532.188	\$ 1,331.567

Duquesne Light Company

Total Stranded Cost Determination
 As of December 31, 1998
 (\$ Millions)

	DLCo			OCA			ALJ			
	Gross	Def. Tax	Net	Gross	Def. Tax	Net	Gross	Def. Tax	Net	Notes
Generating Plant										
Net Book Value of Gen. Plant	\$1,370.53	\$452.92	\$917.61	\$1,365.94	\$452.92	\$913.02	\$1,257.33	\$408.78	\$848.55	(ALJ-1)
Working Capital	0.00	0.00	0.00	61.53	0.00	61.53	61.53	0.00	61.53	(ALJ-2)
M&S and Fuel-Related Sunk Costs	41.11	0.00	41.11	0.00	0.00	0.00	41.11	0.00	41.11	(ALJ-3)
PV of BV2 Lease Expense (1)	475.57	197.33	278.24	513.36	213.01	300.35	513.36	213.01	300.35	(ALJ-4)
Net Book Value	1,887.21	650.25	1,236.96	1,940.83	665.93	1,274.90	1,873.33	621.79	1,251.54	
P V of Decommissioning	123.90	0.00	123.90	44.47	0	44.47	44.47	0.00	44.47	(ALJ-5)
PV of Costs Independent of Operation	208.23	0.00	208.23	0	0	0.00	208.23	0.00	208.23	(ALJ-6)
Estimated Market Value	(46.83)	(19.43)	(27.40)	(511.17)	(212.10)	(299.07)	(488.89)	(202.86)	(286.03)	(ALJ-7)
Stranded Generating Plant	2,172.51	630.82	1,541.69	1,474.13	453.83	1,020.30	1,637.14	418.93	1,218.21	
Regulatory Assets										
SFAS 109	\$236.48	\$57.48	\$179.00	\$236.48	\$57.48	\$179.00	\$236.48	\$57.48	\$179.00	(ALJ-8)
Post-2005 - Unamortized Debt Cost	29.92	10.88	19.04	29.34	10.67	18.67	29.92	10.88	19.04	(ALJ-9)
Pre-2006 - Unamortized Debt Cost	16.76	6.96	9.80	16.43	6.82	9.61	16.76	6.96	9.80	(ALJ-9)
Deferred Rate Sync. Costs	25.37	1.87	23.50	26.52	1.95	24.57	25.37	1.87	23.50	(ALJ-10)
Deferred Employee Costs	13.83	0.00	13.83	14.24	0.00	14.24	13.83	0.00	13.83	(ALJ-10)
Deferred Nuclear Maintenance	3.25	1.35	1.90	3.25	1.35	1.90	3.25	1.35	1.90	
DOE Decom and Decon.	5.58	2.33	3.25	5.74	2.40	3.34	5.58	2.33	3.25	(ALJ-10)
Deferred Coal Costs	13.50	0.00	13.50	0.00	0.00	0.00	0.00	0.00	0.00	(ALJ-11)
Deferred Caretaker Costs	6.77	2.85	3.92	0.00	0.00	0.00	0.00	0.00	0.00	(ALJ-12)
BV2 Training Costs	2.42	0.84	1.58	2.42	0.84	1.58	2.42	0.84	1.58	
Low Level Rad. Waste	2.27	0.00	2.27	2.27	0.00	2.27	2.27	0.00	2.27	
Coal Cost Equalization	0.12	0.00	0.12	0.12	0.00	0.12	0.12	0.00	0.12	
Other	0.53	0.00	0.53	0.53	0.00	0.53	0.53	0.00	0.53	
Pre-Accrue Nuclear Outages	17.60	7.31	10.29	0.00	0.00	0.00	17.60	7.31	10.29	(ALJ-13)
Gain on Sale/Leaseback	55.13	0.00	55.13	55.13	0.00	55.13	55.13	0.00	55.13	
Deferred Rate Sych. Costs (Tax)	0.21	0.00	0.21	0.22	0.00	0.22	0.21	0.00	0.21	(ALJ-10)
BV-2 (Tax)	0.17	0.00	0.17	0.17	0.00	0.17	0.17	0.00	0.17	
Deferred Fuel Cost	11.51	4.78	6.73	11.84	4.92	6.92	11.51	4.78	6.73	(ALJ-10)
Transition Costs	18.10	7.51	10.59	18.20	7.61	10.59	18.10	7.51	10.59	(ALJ-14)
SFAS 106	3.28	1.36	1.92	3.37	1.40	1.97	0.00	0.00	0.00	(ALJ-15)
SFAS 109 Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(ALJ-16)
Total Regulatory Assets	462.80	105.52	357.28	426.27	95.44	330.83	439.25	101.31	337.94	
Total Stranded Cost (Standalone)	\$2,635.31	\$736.34	\$1,898.97	\$1,900.40	\$549.27	\$1,351.13	\$2,076.39	\$520.24	\$1,556.15	
Merger Savings	0.00	0.00	0.00	(260.27)	(107.99)	(152.28)	(260.27)	(107.99)	(152.28)	(ALJ-17)
Total Stranded Cost (w/ Merger Savings)	\$2,635.31	\$736.34	\$1,898.97	\$1,640.13	\$441.28	\$1,198.85	\$1,816.12	\$412.25	\$1,403.87	

**Stranded Cost Allowance
with Associated Deferred Taxes
(\$Millions)**

Stand Alone Base Case

<u>Category/Item:</u>	<u>Deferred Taxes</u>	<u>Amount</u>
Duquesne Light Restructuring		
Book Value:		
Generating Plant Book Value	\$ 411.34	\$ 852.03
Beaver Valley 2 Lease PV	\$ 213.01	\$ 300.35
M&S Fuel Related Sunk Costs	-	-
Working Capital	-	\$ 61.53
Costs Independent of Operation	-	-
Generation Market Value	\$ (78.69)	\$ (110.95)
Offset Credit	\$ (154.39)	\$ (217.69)
Total Stranded Generation:	\$ 391.28	\$ 885.27
Decommissioning:		
Nuclear Decommissioning	-	\$ 42.96
Fossil Decommissioning	-	-
Total Decommissioning	\$ -	\$ 42.96
Regulatory Assets:		
FAS 109 (including Plant reversal)	\$ -	\$ -
Post '05 Unamortized Debt Costs	\$ 10.67	\$ 18.67
Pre '06 Unamortized Debt Costs	\$ 6.82	\$ 9.61
Deferred Rate Synch. (Early Window)	\$ 1.87	\$ 23.50
Deferred Employee Costs	-	\$ 14.24
Deferred Nuclear Maintenance	\$ 1.35	\$ 1.90
US DOE Decommissioning	\$ 2.33	\$ 3.25
Deferred Coal Costs	-	-
Deferred Caretaker Costs	-	-
Pre-Accrued Nuclear Outage	-	-
BV2 Training Costs	\$ 0.84	\$ 1.58
Low Level Radioactive Waste	-	\$ 2.27
Coal Cost Equalization	-	\$ 0.12
Transition Costs	\$ 7.51	\$ 10.59
SFAS 106 Deferral	\$ 1.40	\$ 1.97
Deferred Fuel Costs	\$ 17.73	\$ 25.00
Other Regulatory Assets	-	\$ 0.53
Consumer Education	-	\$ 10.00
Sale-Leaseback Tax Effect (Gain)	-	\$ 55.13
Deferred Rate Synch. Costs	-	-
BV2 Tax Effect	-	\$ 0.17
Total Regulatory Assets:	\$ 50.52	\$ 178.53
PA Jurisdictional % (1-FERC Allocation)	99.900%	99.900%
TOTAL STRANDED, STAND ALONE WITH JURISDICTIONAL ALLOCATION	\$ 441.358	\$ 1,105.658

First Year Pilot Revenues

	Revenue Requirements		Allocation of Pilot Revenues
Average Monthly CTC	\$ 23,014,218	80.97%	\$ 23,014,218
Average Monthly Deferred Tax	\$ 5,409,951	19.03%	\$ 5,409,951
Total Monthly	\$ 28,424,169	100.00%	\$ 28,424,169

Total CTC Revenue Requirement: Return Of & On Stranded Costs + Return Of Unamortized Cost Deferred Tax Balance
 Total Monthly CTC Revenues based on Pilot Credit Average Residual CTC of \$0.027246.

Month	Monthly kwh	Deferred Tax		Stranded Cost Revenues	Deferred Tax Revenues	Total Monthly CTC Revenues	Def Tax %	Stranded %	Return %	Amort %
		Stranded	Beg. of Month							
		Deferred Tax	\$ 441,357,762							
		Stranded	\$ 1,105,658,356							
		Stranded	Beg. of Month	Deferred Tax	Beg. of Month					
1	1,043,241,887	\$ 1,105,658,356	\$ 441,357,762	\$ 23,206,396	\$ 5,217,772	\$ 28,424,169	18.36%	81.64%	35.66%	45.99%
2	1,043,241,887	\$ 1,092,587,161	\$ 436,139,990	\$ 23,172,212	\$ 5,251,956	\$ 28,424,169	18.48%	81.52%	35.24%	46.29%
3	1,043,241,887	\$ 1,079,430,331	\$ 430,888,034	\$ 23,137,805	\$ 5,286,364	\$ 28,424,169	18.60%	81.40%	34.81%	46.59%
4	1,043,241,887	\$ 1,066,187,304	\$ 425,601,670	\$ 23,103,171	\$ 5,320,997	\$ 28,424,169	18.72%	81.28%	34.38%	46.90%
5	1,043,241,887	\$ 1,052,857,517	\$ 420,280,673	\$ 23,068,311	\$ 5,355,858	\$ 28,424,169	18.84%	81.16%	33.95%	47.20%
6	1,043,241,887	\$ 1,039,440,400	\$ 414,924,815	\$ 23,033,222	\$ 5,390,946	\$ 28,424,169	18.97%	81.03%	33.52%	47.51%
7	1,043,241,887	\$ 1,025,935,381	\$ 409,533,869	\$ 22,997,904	\$ 5,426,265	\$ 28,424,169	19.09%	80.91%	33.09%	47.82%
8	1,043,241,887	\$ 1,012,341,885	\$ 404,107,604	\$ 22,962,354	\$ 5,461,815	\$ 28,424,169	19.22%	80.78%	32.65%	48.14%
9	1,043,241,887	\$ 998,659,332	\$ 398,645,789	\$ 22,926,571	\$ 5,497,598	\$ 28,424,169	19.34%	80.66%	32.21%	48.45%
10	1,043,241,887	\$ 984,887,138	\$ 393,148,192	\$ 22,890,554	\$ 5,533,615	\$ 28,424,169	19.47%	80.53%	31.76%	48.77%
11	1,043,241,887	\$ 971,024,716	\$ 387,614,577	\$ 22,854,301	\$ 5,569,868	\$ 28,424,169	19.60%	80.40%	31.32%	49.09%
12	1,043,241,887	\$ 957,071,475	\$ 382,044,709	\$ 22,817,810	\$ 5,606,359	\$ 28,424,169	19.72%	80.28%	30.87%	49.41%

Ending Deferred Tax Balance	\$ 376,438,350
Ending Stranded Balance	\$ 943,026,821

Decomposition of Pilot Revenues

Month	Return	Recovery	Ending Balance
1	\$ 10,135,202	\$ 13,071,195	\$ 1,092,587,161
2	\$ 10,015,382	\$ 13,156,830	\$ 1,079,430,331
3	\$ 9,894,778	\$ 13,243,027	\$ 1,066,187,304
4	\$ 9,773,384	\$ 13,329,788	\$ 1,052,857,517
5	\$ 9,651,194	\$ 13,417,117	\$ 1,039,440,400
6	\$ 9,528,204	\$ 13,505,019	\$ 1,025,935,381
7	\$ 9,404,408	\$ 13,593,496	\$ 1,012,341,885
8	\$ 9,279,801	\$ 13,682,553	\$ 998,659,332
9	\$ 9,154,377	\$ 13,772,194	\$ 984,887,138
10	\$ 9,028,132	\$ 13,862,422	\$ 971,024,716
11	\$ 8,901,060	\$ 13,953,241	\$ 957,071,475
12	\$ 8,773,155	\$ 14,044,655	\$ 943,026,821

Duquesne Light Company

CTC, T&D and Shopping Credit in Cents per kwh

Pre-Tax Return: 11.00%

Year	kwh consumed (1)	CTC Revenue Requirement (2)	CTC Rate With GRT (3)	T&D Rate (4)	Bundled Rate Today (5)	Shopping Credit (6)
1999	12,518,902,647	\$ 341,090,023	2.85	2.140	8.78	3.79
2000	13,396,867,288	\$ 309,939,205	2.42	2.140	8.78	4.22
2001	13,617,281,321	\$ 303,322,219	2.33	2.140	8.78	4.31
2002	13,845,460,353	\$ 296,492,227	2.24	2.140	8.78	4.40
2003	14,082,528,386	\$ 288,106,000	2.14	2.140	8.78	4.50
2004	14,331,562,413	\$ 278,129,767	2.03	2.140	8.78	4.61
2005	14,587,560,447	\$ 263,573,878	1.89	2.140	8.78	4.75

Notes:

- (1) OCA's retail kWh for 1999 (PaPUC-mandated level). Thereafter, Duquesne's sales forecast was used.
- (2) CTC collections in 1999 are calculated as a residual using methodology from the pilot. Thereafter, the CTC rates (post-auction) are set at levels to produce shopping credits in the May PaPUC order. The length of the CTC recovery period will be shortened or lengthened depending on the results of Duquesne's auction of generating assets and actual retail sales.
- (3) GRT Gross up is $1/(1-GRT)$, or 1.0460251, to reflect payment of the portion of the GRT on the GRT revenue receipt.
- (4) Figures are illustrative beyond June 2001 when the cap on non-generation charges expires.
- (5) The ECR roll-in in bundled rates is based on the PaPUC-mandated level of fuel and purchased power costs of \$12.80 per MWH.
- (6) Shopping credits in 1999 are based on the pilot methodology. Thereafter, shopping credits (post-auction) are set at levels consistent with the May PaPUC Order. Shopping credits include energy and capacity, T&D losses, ancillary services, and GRT.

Post-Auction CTC Calculation

Total CTC Revenue Requirement: Return Of & On Stranded Costs + Return Of Unamortized Cost Deferred Tax Balance						
After Market Value Offset Credit and Deferred Tax Offset Credit						
		Deferred Tax	\$ 376,438,350			Monthly Return:
		Stranded	\$ 943,026,821			0.9167%
		Stranded	Deferred Tax	Stranded	Monthly Return:	Annual Return:
Month	Monthly kwh	Req. of Month	Req. of Month	Cost Revenue Requirement	Deferred Tax Revenue Req.	Total Monthly Revenue Req.
13	1,116,405,607	\$ 943,026,821	\$ 376,438,350	\$ 20,925,779	\$ 4,902,488	\$ 25,828,267
14	1,116,405,607	\$ 930,745,454	\$ 371,535,862	\$ 20,893,661	\$ 4,934,606	\$ 25,828,267
15	1,116,405,607	\$ 918,383,626	\$ 366,601,256	\$ 20,861,332	\$ 4,966,935	\$ 25,828,267
16	1,116,405,607	\$ 905,940,811	\$ 361,634,321	\$ 20,828,791	\$ 4,999,476	\$ 25,828,267
17	1,116,405,607	\$ 893,416,477	\$ 356,634,845	\$ 20,796,038	\$ 5,032,229	\$ 25,828,267
18	1,116,405,607	\$ 880,810,090	\$ 351,602,616	\$ 20,763,069	\$ 5,065,198	\$ 25,828,267
19	1,116,405,607	\$ 868,121,113	\$ 346,537,418	\$ 20,729,885	\$ 5,098,382	\$ 25,828,267
20	1,116,405,607	\$ 855,349,005	\$ 341,439,036	\$ 20,696,483	\$ 5,131,784	\$ 25,828,267
21	1,116,405,607	\$ 842,493,222	\$ 336,307,252	\$ 20,662,862	\$ 5,165,405	\$ 25,828,267
22	1,116,405,607	\$ 829,553,214	\$ 331,141,847	\$ 20,629,021	\$ 5,199,246	\$ 25,828,267
23	1,116,405,607	\$ 816,528,430	\$ 325,942,601	\$ 20,594,959	\$ 5,233,308	\$ 25,828,267
24	1,116,405,607	\$ 803,418,315	\$ 320,709,293	\$ 20,560,673	\$ 5,267,594	\$ 25,828,267
25	1,134,773,443	\$ 790,222,310	\$ 315,441,699	\$ 20,132,064	\$ 5,144,788	\$ 25,276,852
26	1,134,773,443	\$ 777,333,950	\$ 310,296,911	\$ 20,098,358	\$ 5,178,493	\$ 25,276,852
27	1,134,773,443	\$ 764,361,154	\$ 305,118,418	\$ 20,064,431	\$ 5,212,420	\$ 25,276,852
28	1,134,773,443	\$ 751,303,366	\$ 299,905,998	\$ 20,030,283	\$ 5,246,569	\$ 25,276,852
29	1,134,773,443	\$ 738,160,031	\$ 294,659,429	\$ 19,995,910	\$ 5,280,942	\$ 25,276,852
30	1,134,773,443	\$ 724,930,588	\$ 289,378,487	\$ 19,961,312	\$ 5,315,540	\$ 25,276,852
31	1,134,773,443	\$ 711,614,473	\$ 284,062,947	\$ 19,926,488	\$ 5,350,364	\$ 25,276,852
32	1,134,773,443	\$ 698,211,118	\$ 278,712,583	\$ 19,891,435	\$ 5,385,417	\$ 25,276,852
33	1,134,773,443	\$ 684,719,952	\$ 273,327,167	\$ 19,856,153	\$ 5,420,699	\$ 25,276,852
34	1,134,773,443	\$ 671,140,399	\$ 267,906,468	\$ 19,820,639	\$ 5,456,212	\$ 25,276,852
35	1,134,773,443	\$ 657,471,880	\$ 262,450,255	\$ 19,784,893	\$ 5,491,959	\$ 25,276,852
36	1,134,773,443	\$ 643,713,812	\$ 256,958,297	\$ 19,748,913	\$ 5,527,939	\$ 25,276,852
37	1,153,788,363	\$ 629,865,610	\$ 251,430,358	\$ 19,305,912	\$ 5,401,774	\$ 24,707,686
38	1,153,788,363	\$ 616,333,466	\$ 246,028,584	\$ 19,270,522	\$ 5,437,163	\$ 24,707,686
39	1,153,788,363	\$ 602,712,667	\$ 240,591,420	\$ 19,234,901	\$ 5,472,785	\$ 24,707,686
40	1,153,788,363	\$ 589,002,633	\$ 235,118,635	\$ 19,199,046	\$ 5,508,639	\$ 24,707,686
41	1,153,788,363	\$ 575,202,777	\$ 229,609,996	\$ 19,162,957	\$ 5,544,729	\$ 24,707,686
42	1,153,788,363	\$ 561,312,513	\$ 224,065,267	\$ 19,126,631	\$ 5,581,055	\$ 24,707,686
43	1,153,788,363	\$ 547,331,247	\$ 218,484,212	\$ 19,090,067	\$ 5,617,619	\$ 24,707,686
44	1,153,788,363	\$ 533,258,384	\$ 212,866,593	\$ 19,053,263	\$ 5,654,423	\$ 24,707,686
45	1,153,788,363	\$ 519,093,323	\$ 207,212,170	\$ 19,016,218	\$ 5,691,467	\$ 24,707,686
46	1,153,788,363	\$ 504,835,460	\$ 201,520,703	\$ 18,978,931	\$ 5,728,755	\$ 24,707,686
47	1,153,788,363	\$ 490,484,187	\$ 195,791,948	\$ 18,941,399	\$ 5,766,286	\$ 24,707,686
48	1,153,788,363	\$ 476,038,893	\$ 190,025,662	\$ 18,903,622	\$ 5,804,064	\$ 24,707,686
49	1,173,544,032	\$ 461,498,961	\$ 184,221,598	\$ 18,366,124	\$ 5,642,709	\$ 24,008,833
50	1,173,544,032	\$ 447,363,244	\$ 178,578,889	\$ 18,329,156	\$ 5,679,677	\$ 24,008,833
51	1,173,544,032	\$ 433,134,918	\$ 172,899,212	\$ 18,291,946	\$ 5,716,887	\$ 24,008,833
52	1,173,544,032	\$ 418,813,375	\$ 167,182,324	\$ 18,254,492	\$ 5,754,341	\$ 24,008,833
53	1,173,544,032	\$ 404,398,005	\$ 161,427,983	\$ 18,216,793	\$ 5,792,040	\$ 24,008,833
54	1,173,544,032	\$ 389,888,194	\$ 155,635,943	\$ 18,178,847	\$ 5,829,987	\$ 24,008,833
55	1,173,544,032	\$ 375,283,322	\$ 149,805,956	\$ 18,140,652	\$ 5,868,182	\$ 24,008,833
56	1,173,544,032	\$ 360,582,768	\$ 143,937,775	\$ 18,102,207	\$ 5,906,627	\$ 24,008,833
57	1,173,544,032	\$ 345,785,903	\$ 138,031,148	\$ 18,063,510	\$ 5,945,324	\$ 24,008,833
58	1,173,544,032	\$ 330,892,097	\$ 132,085,825	\$ 18,024,559	\$ 5,984,274	\$ 24,008,833
59	1,173,544,032	\$ 315,900,716	\$ 126,101,550	\$ 17,985,354	\$ 6,023,480	\$ 24,008,833
60	1,173,544,032	\$ 300,811,119	\$ 120,078,071	\$ 17,945,891	\$ 6,062,942	\$ 24,008,833
61	1,194,296,868	\$ 285,622,663	\$ 114,015,128	\$ 17,311,999	\$ 5,865,482	\$ 23,177,481
62	1,194,296,868	\$ 270,928,872	\$ 108,149,647	\$ 17,273,571	\$ 5,903,909	\$ 23,177,481
63	1,194,296,868	\$ 256,138,815	\$ 102,245,738	\$ 17,234,892	\$ 5,942,588	\$ 23,177,481
64	1,194,296,868	\$ 241,251,862	\$ 96,303,149	\$ 17,195,960	\$ 5,981,521	\$ 23,177,481
65	1,194,296,868	\$ 226,267,377	\$ 90,321,629	\$ 17,156,772	\$ 6,020,708	\$ 23,177,481
66	1,194,296,868	\$ 211,184,723	\$ 84,300,920	\$ 17,117,328	\$ 6,060,153	\$ 23,177,481
67	1,194,296,868	\$ 196,003,255	\$ 78,240,767	\$ 17,077,625	\$ 6,099,856	\$ 23,177,481
68	1,194,296,868	\$ 180,722,327	\$ 72,140,912	\$ 17,037,662	\$ 6,139,819	\$ 23,177,481
69	1,194,296,868	\$ 165,341,286	\$ 66,001,093	\$ 16,997,437	\$ 6,180,043	\$ 23,177,481
70	1,194,296,868	\$ 149,859,477	\$ 59,821,050	\$ 16,956,949	\$ 6,220,532	\$ 23,177,481
71	1,194,296,868	\$ 134,276,240	\$ 53,600,518	\$ 16,916,196	\$ 6,261,285	\$ 23,177,481
72	1,194,296,868	\$ 118,590,910	\$ 47,339,233	\$ 16,875,175	\$ 6,302,306	\$ 23,177,481
73	1,215,630,037	\$ 102,802,819	\$ 41,036,928	\$ 15,966,957	\$ 5,997,533	\$ 21,964,490
74	1,215,630,037	\$ 87,778,221	\$ 35,039,394	\$ 15,927,664	\$ 6,036,826	\$ 21,964,490
75	1,215,630,037	\$ 72,655,191	\$ 29,002,569	\$ 15,888,114	\$ 6,076,376	\$ 21,964,490
76	1,215,630,037	\$ 57,433,082	\$ 22,926,193	\$ 15,848,305	\$ 6,116,185	\$ 21,964,490
77	1,215,630,037	\$ 42,111,247	\$ 16,810,008	\$ 15,808,235	\$ 6,156,255	\$ 21,964,490
78	1,215,630,037	\$ 26,689,032	\$ 10,653,753	\$ 15,767,903	\$ 6,196,587	\$ 21,964,490
79	1,215,630,037	\$ 11,165,779	\$ 4,457,166	\$ 15,727,306	\$ 6,237,184	\$ 21,964,490

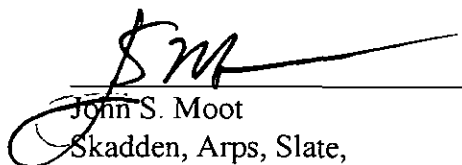
**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

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 a copy of the Reply Comments of Duquesne Light Company on the Generation Auction Plan was served, by first-class mail, upon the participants on the attached service list in accordance with Section 1.54 of the Commission's regulations.

Dated this 23rd day of November, 1998.



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ORIGINAL

November 24, 1998

Via Overnight Mail

Mr. James J. McNulty
Secretary
Pennsylvania Public Utility Commission
North Office Building
North St. & Commonwealth Ave.
Harrisburg, PA 17105-3265

RECEIVED

NOV 24 1998

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Re: Duquesne Light Company
Docket No. R-00974104

Dear Mr. McNulty:

Enclosed is an original and nine copies of Duquesne Light Company's Limited Supplemental Reply Comments to Further Comments of Green Mountain Energy Resources regarding Stand-Alone Restructuring Plan. 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,



Victor A. Contract
Counsel to Duquesne Light Company

Enclosure

DOCUMENT
FOLDER

36

ORIGINAL

RECEIVED

NOV 24 1998

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION** PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

**Pennsylvania Public Utility
Commission,
v.
Duquesne Light Company
Application to approve
restructuring plan pursuant
to 66 Pa. C.S. § 2806(d)**)
)
)
)
)
)
)

Docket No. R-00974104

**LIMITED SUPPLEMENTAL REPLY COMMENTS OF DUQUESNE LIGHT
COMPANY TO FURTHER COMMENTS OF GREEN MOUNTAIN EN-
ERGY RESOURCES ON THE SUPPLIER TARIFF THIRD COMPLIANCE
FILING OF DUQUESNE LIGHT COMPANY STAND-ALONE RESTRUC-
TURING PLAN**

Duquesne Light Company ("Duquesne") hereby submits limited supplemental reply comments to respond to Green Mountain Energy Resources L.L.C.'s ("Green Mountain") "Further Comments of Green Mountain Energy Resources on the Supplier Tariff Third Compliance Filing of Duquesne Light Company Regarding Stand-Alone Restructuring Plan." Duquesne did not respond to these comments in its previously filed Reply Comments dated November 20, 1998 because Green Mountain's comments were filed eight days after parties' reply comments were due. See Second Compliance Order at 41. Consequently, Duquesne discusses herein matters that were not known at the time Duquesne filed its November 20 Reply Comments.

DOCKETED
NOV 25 1998

**DOCUMENT
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1. Scheduling Coordinators

Green Mountain desires for the Scheduling Coordinator to sign and to be primarily responsible to Duquesne under the Supplier Tariff because this would be consistent with Green Mountain's existing contractual arrangements. Green Mountain Comments at 2. Green Mountain recommends the use of a designated agent under the Supplier Tariff, as permitted under Duquesne's OATT. Green Mountain is attempting to apply the requirements and obligations under the OATT to the Supplier Tariff. Green Mountain fails to recognize that both tariffs serve distinct regulatory purposes and have distinct regulatory requirements. With regard to the Supplier Tariff, which is presently at issue, Green Mountain's proposal may force Duquesne to look to a non-PaPUC licensed EGS for payment and other obligations that have not been specifically designated to a Scheduling Coordinator. See Supplier Tariff Scheduling Coordinator Designation Form. This proposal thwarts the ability of Duquesne to hold only a licensed EGS primarily responsible for performance of obligations, as envisioned under the Competition Act.

2. Multiple Scheduling Coordinators

Green Mountain wishes to expand the Supplier Tariff to permit "the use of multiple Scheduling Coordinators by a single EGS" for the purpose of "providing full requirements service to an EGS up to a certain number of

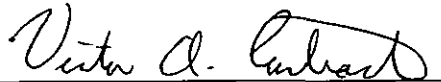
[C]ustomers or volume of load. An additional [S]cheduling [C]oordinator for the EGS will be needed at the time that limit is reached." Green Mountain Comments at 4-5. Duquesne reiterates that an EGS may assign specific Customers to a particular Scheduling Coordinator. However, Green Mountain's suggestion that, a Scheduling Coordinator may provide full requirements service up to a certain number of Customers or a certain volume of load, should be rejected. Under such a proposal, it is conceivable that the first 100 MW of load for specific Customers of the EGS would be supplied by "Scheduling Coordinator 1" and then the next 50 MW of load for the same group of Customers of the EGS would be supplied by "Scheduling Coordinator 2". Duquesne states that it would be difficult, if not impossible, to accommodate this simultaneous use of multiple Scheduling Coordinators for individual Customer accounts. Moreover, neither the PECO nor the PP&L Supplier Tariffs, which the Commission directed Duquesne to use as a model for its Supplier Tariff, permit this use of multiple Scheduling Coordinators.

Green Mountain refers to the proposed West Penn Power Tariff, but this proposal was not considered by Duquesne or interested parties because it was not filed until November 4th, the day before Duquesne's Third Compliance Filing was due. Nevertheless, Duquesne's Supplier Tariff presently accommodates what Green Mountain favors in West Penn's proposed Tariff (which West Penn may agree to provide sometime in the future) -- namely, "the designation of a Scheduling Coordi-

nator for each customer ... [and to] permit multiple Scheduling Coordinators for an EGS." Green Mountain Comments at 5 (quoting West Penn Power § 9.6) (emphasis added).

WHEREFORE, Duquesne's Third Compliance Filing should be accepted without modification or condition for the reasons stated above.

Respectfully submitted,



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Corporate Attorney
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Skadden, Arps, Slate, Meagher & Flom LLP
1440 New York Ave., N.W.
Washington, D.C. 20005
(202) 371-7310

Dated: November 24, 1998

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

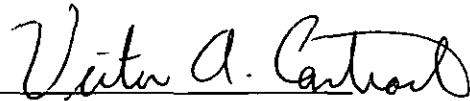
Pennsylvania Public Utility)
Commission,)
v.)
Duquesne Light Company)
Application to approve)
restructuring plan pursuant)
to 66 Pa. C.S. § 2806(d))

Docket No. R-00974104

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing document was served, by first-class mail, upon the participants on the attached service list in accordance with Section 1.54 of the Commission's regulations.

Dated this 24th day of November, 1998.



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Counsel to
Duquesne Light Company



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

IN REPLY PLEASE
REFER TO OUR FILE

November 30, 1998

RECEIVED
NOV 30 1998

The Honorable David K. Levdansky
House of Representatives
House Post Office - Main Capitol
Harrisburg, PA

PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Dear Representative Levdansky:

Thank you for your letter of November 19, 1998, to Chairman John M. Quain of the Pennsylvania Public Utility Commission regarding the application of the Duquesne Light Company for approval of its divestiture plan at ~~Docket Number R-00974104.~~ Since this matter is currently pending before the Commission, Chairman Quain referred your letter to me for a response.

Please know that I have taken the liberty of forwarding your comments and concerns to the Secretary of the Commission for inclusion into the official file of this proceeding.

Thank you again for the benefit of your thinking on this important matter.

Sincerely,

Rosemary Chiavetta, Esq.
Director of Legislative Affairs

cc: Chairman Quain
Vice Chairman Bloom
Commissioner Rolka
Commissioner Brownell
Commissioner Wilson
Secretary McNulty ✓

DOCKETED
JAN 06 1999

DOCUMENT
FOLDER

SRB

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House of Representatives
COMMONWEALTH OF PENNSYLVANIA
HARRISBURG

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SUBCOMMITTEE CHAIRMAN, MINING
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TRANSPORTATION, SUBCOMMITTEE
CHAIRMAN, RAILROADS

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50 NOV 23 PM 3:11
CHAIRMAN QUAIN'S OFFICE

November 19, 1998

The Honorable John M. Quain, Chairman
Pennsylvania Public Utility Commission
Room 104, North Office Building
Harrisburg, PA 17120

Dear Commissioner Quain:

I am writing to express my concerns regarding the application of Duquesne Light Company for approval of its restructuring plan under section 2806 of the Pennsylvania Public Utility Code; Docket No. R-0097104. I have a number of substantial concerns about the proposed transfer of assets in the restructuring plans.

First, and foremost, is my concern about the impact of the plan on the employees of these facilities. It was clearly the intent of the General Assembly to have employees of any affected facilities actively participate in "competition" related decisions when the Electric Restructuring Act was passed in 1996. Therefore, I believe the Public Utility Commission has a responsibility to require that the employees and their representatives of any affected facilities actively participate in the discussions and come to some agreement on such issues as collective bargaining agreements; reductions in force; severance pay; early retirement incentives; retraining, relocation and outplacement services; protection of employee pension rights; protection of health care benefits and other benefits the employees currently enjoy.

There are also a number of other issues such as the overall impact on economic development efforts in our region, the impact on local zoning and planning, responsibilities for plant decommissioning, alternative suppliers, the long term impact on utility costs and the potential transfer of air quality credits. Each of these issues need to be addressed with a careful eye on the impact of the restructuring plan on the employees, ratepayers, communities and our overall environment.

I would appreciate it if you could convey my concerns about these issues to your colleagues on the Commission as they review the restructuring plan.

Sincerely,

A handwritten signature in dark ink, appearing to read "David K. Levdansky".

DAVID K. LEVDANSKY
State Representative
39th District