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January 8, 1998

Via Federal Express

James J. McNulty III
Prothonotary
Pennsylvania Public Utility Commission
North Office Building
Commonwealth Ave. And North St.
Harrisburg, PA 17120

Re: Duquesne Light Company: Application for Approval of Restructuring Plan, Docket No. R-00974104

Dear Mr. McNulty:

Pursuant to Judge Corbett's Sixth Interim Order in the above-referenced proceeding, enclosed are the original and one copy of the First Joint Stipulation of the parties, signed by NEV East, LLC, along with two copies each of the direct testimony and exhibits of NEV East, LLC witnesses David M. Boonin and Nancy I. Day. Copies of the signed Stipulation and accompanying indices of the intervenors' testimony and exhibits have been served on all parties of record in accordance with the attached Certificate of Service. Copies of the direct testimony and exhibits of Mr. Boonin and Ms. Day were previously served on all parties of record.

Sincerely,

Luke E. Dembosky

LED:pk
Enc.
cc: All parties of record (w/enc.) (via first class mail)
Honorable John H. Corbett, Jr., ALJ (w/enc.) (via federal express)

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)	)	

FIRST JOINT STIPULATION

Pursuant to an agreement of all parties to this case and as required by the Sixth Interim Order issued by the Presiding Judge on December 30, 1997, Duquesne Light Company ("Duquesne") and the intervenor parties hereby agree and stipulate to the following:

1. Each party to this Stipulation agrees that the testimony and exhibits itemized on the Stipulation Exhibits attached hereto shall be admitted into the record of this case.

2. Each party to this Stipulation agrees to waive its right to cross-examine the witnesses sponsoring the testimony and exhibits itemized on the Stipulation Exhibits attached hereto.

3. Each party to this Stipulation agrees to execute a copy of this Stipulation by causing counsel of record for each party (or the party itself if that party is unrepresented by counsel) to place its signature on the appropriate line below. Each party further agrees to file an executed version thereof with the Commission's Secretary and Prothonotary at the time it submits two copies of its testimony and exhibits to the Secretary and Prothonotary, as prescribed by the Sixth Interim Order.

Counsel for Duquesne Light: _____
John S. Moot

Counsel for Intervenor Party: _____

Name of Intervenor Party: NEV East LLC

Dated: January 7, 1998

FIRST JOINT STIPULATION
INDICES OF TESTIMONY & EXHIBITS

Exhibit No.	Description
1	City of Pittsburgh
2	Duquesne Industrial Intervenors (DII)
3	Enron Power Marketing, Inc. (ENRON)
4	Environmentalists (ENV)
5	Hospital Shared Services & Administrative Resources, Inc. (HSS/ARI)
6	International Brotherhood of Electrical Workers (IBEW)
7	Mid-Atlantic Power Supply Association (MAPSA)
8	New Energy Ventures (NEV)
9	Office of Business Advocate (OSBA)
10	Office of Consumer Advocate (OCA)
11	Office of Trial Staff (OTS)
12	Pennsylvania Retailers Association (PRA)

FIRST JOINT STIPULATION
EXHIBIT NO. 1

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
DUQUESNE LIGHT COMPANY

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

CITY OF PITTSBURGH
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Brief Description
City Statement No. 1	Direct Testimony of Christopher D. Seiple (addressing issues pertaining to the Company's general overview/recovery plan and stranded costs).
City Exhibit No. 1	Resource Data International Background & History.
City Exhibit No. 2	RDI Market & Competitor Intelligence
City Exhibit No. 3 (incl. Tables 1-3)	Capacity Factor Analysis
City Exhibit No. 4	Delivered Output Analysis
City Exhibit No. 5	Early Plant Shutdown Savings Analysis
City of Pittsburgh, *et al.* Statement No. 2	Direct Testimony of Roger D. Colton (addressing issues pertaining to universal service, low income programs, energy conservation, consumer education, and phase-in).
Exhibit RDC-1	Resume of Roger D. Colton
Exhibit RDC-2	Summary of Colton electricity restructuring experience.
Exhibit RDC-3	Summary of Colton experience pertaining to design of low-income affordability programs.
Exhibit RDC-4	Number and Percent of LIHEAP Recipients by Income Range and Annual Electric Burdens.
Exhibit RDC-5	Recommendations pertaining to utility universal service programs which can help increase incomes of low-income consumers.
Exhibit RDC-6	Estimate of Universal Service Costs at 50 Percent CAP Participation.

Exhibit RDC-7	Summary of Universal Service Recommendations.
Exhibit RDC-8	Recommendations for Consumer Research section of an Education Plan
Exhibit RDC-9	Model 4-Phase Consumer Education Program
Exhibit RDC-10	Proposed Evaluation Process for Consumer Education Activities
Exhibit RDC-11	Summary of Consumer Education Recommendations
Exhibit RDC-12	Proposed Budget for Universal Service Programs

FIRST JOINT STIPULATION
EXHIBIT NO. 2

DUQUESNE INDUSTRIAL INTERVENORS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
DII Statement No. 1	**Direct Testimony of Stephen J. Baron (Summary of Stranded Cost Analysis; Regulatory Policy Issues; Rate Design Issues)**		
Exhibit SJB-1	Expert Testimony Appearances		
Exhibit SJB-2	DII Summary of *Recommended* Stranded Costs		
Exhibit SJB-3	Example of DII Stranded Generation Sharing Analysis		
Exhibit SJB-4	DII Calculation of Adjusted Rate of Return		
Exhibit SJB-5	DII Summary of Estimated CTC Revenues by Rate Class		
Exhibit SJB-6	DII Load-weighted Market Prices		
Exhibit SJB-7	DII Unbundling Analysis for Rate RS		
Exhibit SJB-8	DII Unbundling Analysis for Rate L		
Exhibit SJB-9	DII Unbundling Analysis for Rate HVPS		

DUQUESNE INDUSTRIAL INTERVENORS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
DII Statement No. 1R	**Rebuttal Testimony of Stephen J. Baron (Universal Service Cost Recovery Mechanism; Issues Regarding the Calculation of Market Prices and Stranded Cost; Response to OCA Regarding Unbundling Issues)**		
DII Statement No. 1S	**Surrebuttal Testimony of Stephen J. Baron (Responses to Company Witnesses Regarding Divestiture, Stranded Cost Sharing, CTC Calculation, and Rate Design Issues; Response to OSBA Witness Regarding CTC Calculation and Recovery)**		
DII Statement No. 2	**Direct Testimony of Randall J. Falkenberg (Calculation of Company Generation Stranded Cost; Analysis of Duquesne and ECAR Market Prices)**		
Exhibit RJF-1	Qualifications of Randall J. Falkenberg		
Exhibit RJF-2	Production Cost Model Studies and Benchmarks		
Exhibit RJF-3	Comparison of Market Price Model Results of K&A Model v. MAPS, IPM and PMDAM		
Exhibit RJF-4	DII Calculation of Company's Annual Revenue Requirements for Generation		
Exhibit RJF-5a	DII Total Generation Stranded Cost Calculation		
Exhibit RJF-5b	DII Calculation of Net Present Value of Contribution Margins		
Exhibit RJF-5c	DII Summary of Market Prices, Fuel Cost, Operating Margin and Generation by Plant		

DUQUESNE INDUSTRIAL INTERVENORS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
DII Statement No. 2S	**Surrebuttal Testimony of Randall J. Falkenberg (Updated Calculation of Generation Stranded Costs; Responses to Company Witnesses Regarding Market Price Forecasts)**		
Exhibit RJF-6a	DII Updated Total Generation Stranded Cost Calculation		
Exhibit RJF-6b	DII Updated Calculation of Net Present Value of Contribution Margins		
Exhibit RJF-6c	DII Updated Summary of Market Prices, Fuel Cost, Operating Margin and Generation by Plant		
DII Statement No. 3	**Direct Testimony of Lane Kollen (Regulatory Assets; Transition Costs; Fossil Decommissioning; Nuclear Decommissioning; Securitization)**		
Exhibit LK-1	Resume of Lane Kollen		
Exhibit LK-2	Excerpts from Company Exhibits Illustrating Double Counting of FAS 109 Asset Related to Perry and Beaver Valley 1		
Exhibit LK-3	Excerpt from Company First Quarter 1997 SEC 10-Q Related to Deferred Coal		
Exhibit LK-4	Net Present Value of Deferred Rate Synchronization Costs at 12/31/98		
Exhibit LK-5	Duquesne Nuclear Decommissioning for Stranded Cost and Revenue Requirement (Beaver Valley 1, Beaver Valley 2, and Perry)		

DUQUESNE INDUSTRIAL INTERVENORS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
DII Statement No. 3S	**Surrebuttal Testimony of Lane Kollen (Responses to Company Witnesses Regarding Stranded Cost Methodology, Unamortized Debt Costs, Beaver Valley 2 Sale/Leaseback Refinancing Premium, Preaccrued Nuclear Outages, Deferred Employee Costs, Deferred Coal SFAS 106, Deferred Rate Synchronization Costs, Fossil Decommissioning, Securitization)**		
DII Cross Exh. 1	Response of Company Witness Hoffmann to Environmentalists' Interrogatories Set I, Number 23	12/18/97	12/18/97
DII Cross Exh. 2	Response of Company Witness Hoffmann to On-the-Record Data Request Concerning Customer Segment Contribution to Non-Coincident Peak Load		
DII Cross Exh. 3	Response of Company Witness Hoffmann to On-the-Record Data Request Concerning Mining, Construction, and Agriculture Customer Segments		

DUQUESNE LIGHT COMPANY

On-the-Record Data Requests

3. Provide a non-coincident peak calculation in form that is analogous to the coincident peak calculation provided in response to Data Request ENV-1-23.

Response:

Attached is a modified version of DLC's response to ENV-1-23 which list the non-coincidental peak load contribution for each customer group/segment associated with the proposed phase-in methodology.

Non-Coincidental Peak Load Contribution by Customer Class and Segment

Customer Class	Customer Group/Segment	Non-Coincidental Peak Contribution	Percentage Contribution to Non-Coincidental Peak
Residential	Group A - Accumulated Wealth	41	1.14%
	Group B - Mainstream Families	374	10.42%
	Group C - Mainstream Singles	273	7.60%
	Group D - Conservative Classics	49	1.36%
	Group E - Sustaining Families	49	1.36%
	Group F - Sustaining Singles	65	1.82%
	Group G - All Others	21	0.58%
	Subtotal Residential	**871**	**24.28%**
Commercial	Utility Services	155	4.33%
	Wholesale Trade	53	1.47%
	Retail Trade - Food	71	1.99%
	Retail Trade - Restaurants	85	2.36%
	Retail Trade - Merchandise	177	4.94%
	Office Buildings	399	11.13%
	Healthcare	142	3.95%
	Education	214	5.98%
	Services	283	7.89%
	Government	82	2.29%
	Small Business	324	9.04%
	Subtotal Commercial	**1,986**	**55.36%**
Industrial	Industrial - Chemical	68	1.88%
	Industrial - Plastic	14	0.39%
	Industrial - Glass	39	1.08%
	Industrial - Steel	449	12.52%
	Industrial - Other	161	4.48%
	Subtotal Industrial	**730**	**20.36%**
	TOTALS	**3,587**	**100.00%**

DUQUESNE LIGHT COMPANY

On-the-Record Data Requests

4. Provide breakdown of numbers for mining, construction and agriculture segments on FAH-4 in a manner comparable to that provided in response to ENV-1-23.

Response:

The market segments listed on FAH-4 as "Mining" and "Construction" are classified as "Industrial-Other" on the response to ENV-1-23. Similarly, "Agriculture" was classified within the "services" market segment.

FIRST JOINT STIPULATION
EXHIBIT NO. 3

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
DUQUESNE LIGHT COMPANY

Application for Approval of a Restructuring Plan
Pursuant to 66 Pa. C.S. § 2806(d)
Docket No. R-00974104

ENRON POWER MARKETING, INC.
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
Enron Cross Examination Exhibit No. 1	CFR Uniform System of Accounts: Accounts 908 and 909.	12/17/97	12/17/97
Enron Statement No. 1	**Direct Testimony of James D. Steffes** General overview of competitive services; the Portland General Code of Conduct.		
Exhibit 1 JDS-1	Market share of utilities/affiliates in Retail Access Programs.		
Exhibit 1 JDS-2	Portland General Electric Company Tariff Code of Conduct.		
Exhibit 1 JDS-3	Market share of affiliates in Retail Access Programs.		
Enron Statement No. 2	**Direct Testimony of Paul D. Reising** Rates for unbundled services of Transmission, Ancillary, Energy Delivery and Revenue cycles separately computed and stated.		
Exhibit 2 PDR-1	Educational and employment background of P.D. Reising.		
Exhibit 2 PDR-2	Definition and Description of Ancillary Services.		

Exhibit 2 PDR-3	Summary of Functional Costs.		
Exhibit 2 PDR-4	EPMI Proposed Class Rates		
Exhibit 2 PDR-5	EPMI Class Cost Summary		
Exhibit 2 PDR-6	pro forma Distribution Services Tariff		
Exhibit 2 PDR-7	Energy Delivery Rate Design		
Enron Statement No. 3	**Direct Testimony of Jeffrey A. Brown** Non-wire services, metering, meter-reading, billing and information services. "Open architecture" communication systems.		
Exhibit 3 JAB-1	Customer Account Services: Billing System Opportunities (representative example)		
Exhibit 3 JAB-2	Customer Account Services: Third Party Billing Services (representative example)		
Exhibit 3 JAB-3	Non-Wire Products and Services: "Endless Possibilities"		
Exhibit 3 JAB-4	Non-Wire Communications Network: Conceptual Model		
Exhibit 3 JAB-5	Metering and Billing Cycle		
Enron Statement No. 4	**Direct Testimony of Gayle Muench** Unbundling of billing and bill format; billing options ("Supplier Complete Bill Option"); phase-in of competition; customer selection and "slamming"; customer information ("Customer Education Program"); Duquesne's Universal Service Program in a competitive environment.		
Exhibit 4 GM-1	DQE Position on Competition		
Exhibit 4 GM-2	DQE Overview of Competition		
Enron Statement No. 5	**Direct Tetsimony of Lynn R. Coles** "Pro Forma Supplier Tariff." Access to point-to-point transmission service. EDC charges; minimum contract periods; planning reserves.		

Exhibit 5 LRC-1	Summary of educational background and general experience in electric utility industry.		
Exhibit 5 LRC-2	Proposed Electric Generation Supplier Tariff.		
Exhibit 5 LRC-3	GPU Market Line: Energy market prices; viability payments, all-in market line; market clearing prices.		
Enron Statement No. 1.1	**Surrebuttal Testimony of James D. Steffes** Response to Duquesne witnesses Hoffman and Allison.		
Enron Statement No. 2.1	**Surrebuttal Testimony of Paul D. Reising** Responses to rebuttal testimony of Duquesne witness Lahtinen; IBEW witness Moran; and OCA witness Alexander.		
Exhibit 2.1 PDR-8	Revised functional cost of service summary.		
Exhibit 2.1 PDR-9	Revised versions of class-based T & D charges (original Exhibit 2 PDR-4).		
Exhibit 2.1 PDR-10	Revised versions of voltage differentiated rates (original Exhibit 2 PDR-5).		
Enron Statement No. 3.1	**Surrebuttal Testimony of Jeffrey A. Brown** Responses to Duquesne witness Allison; and IBEW witnesses Schmidt and Moran.		
Enron Statement No. 4.1	**Surrebuttal Testimony of Gayle Muench** Responses to Duquesne witnesses Allison, Hoffman and Flynn; OCA witness Alexander; and IBEW witness Moran.		
Enron Statement No. 5.1	**Surrebuttal Testimony of Lynn R. Coles** Responses to rebuttal testimony of IBEW witness Moran; and witnesses Irvin and Karl.		

FIRST JOINT STIPULATION
EXHIBIT NO. 4

Roger E. Clark, Esq.

Attorney for The Environmentalists

505 Denston Drive
Ambler, PA 19002-3901
phone: 215.643.2204
fax: 215.628.2630
e-mail: rclark@libertynet.org

January 7, 1998

John Moot
Skadden, Arps, Slate, Meagher & Flom LLP
1440 New York Avenue, N.W.
Washington, D.C. 20005-2111

Re: Duquesne Light Company Application for Approval of a Restructuring Plan, Docket No. R-0097104.

Dear Mr. Moot:

Thank you for catching our oversight regarding Roger Colton's surrebuttal testimony. In accordance with the Sixth Interim Order issued by Judge Corbett on December 30, 1997, I am sending you the following updated index of the Environmentalists' testimony and exhibits in the above-referenced proceeding:

Exhibit	Description	Date Identified	Date Admitted
Environmentalists' Statement No. 1	Direct Testimony of David Schoengold		
Ex. DS-1	Resume of David Schoengold		
Ex. DS-2	*Environmentalists' Vision for the New Electricity Marketplace*		
Ex. DS-3	Return on the Investment to Date for Stockholders		
Ex. DS-4	Total Return to Date for Stockholders		
Ex. DS-5	Methodology for Determining Total Return Of and On Investment for Stockholders Through End of Transition Period		
Ex. DS-6	Proposed Draft for Net Billing Tariff		

Environmentalists' Index of Testimony and Exhibits
January 7, 1998
Page 2

Environmentalists' Statement No. 1-S	Surrebuttal Testimony of David Schoengold		
Environmentalists' Statement No. 2	Direct Testimony of Bruce Biewald		
Ex. BEB-1	Resume of Bruce Biewald		
Ex. BEB-2	Graph of TLG Decommissioning Estimates: 1977-1995		
Ex. BEB-3	*Full Environmental Disclosure for Electricity: Tracking and Reporting Key Information*, March 1997		
Ex. BEB-4	Better Choice Plan - Three Examples		
Environmentalists' Statement 2-S	Surrebuttal Testimony of Bruce Biewald		
Ex. BEB-5	Economic Analysis of Duquesne Light Company's Perry 1 Investment		
Ex. BEB-6	Economic Analysis of Duquesne Light Company's Beaver Valley 2 Investment		
Ex. BEB-7	Assumptions for Economic Analysis for Perry 1 and Beaver Valley 2		
City of Pittsburgh *et al.* Statement No. 2 (cosponsored with the Environmentalists)	Direct Testimony of Roger Colton		
Ex. RDC-1	Resume of Roger Colton		
Ex. RDC-2	Summary of Roger Colton's Restructuring Work		
Ex. RDC-3	Summary of Roger Colton's Energy Efficiency Work		
Ex. RDC-4	Number and Percentage of LIHEAP Recipients by Income Range		

Ex. RDC-5	Summary of the BOSS and Earned Income Tax Credit Outreach		
Ex. RDC-6	Estimate of Universal Service Program Costs		
Ex. RDC-7	Summary of Universal Service Recommendations		
Ex. RDC-8	Summary of Consumer Research Section of Consumer Education Plan		
Ex. RDC-9	Four Phase Consumer Education Program		
Ex. RDC-10	Consumer Education Evaluation Process		
Ex. RDC-11	Summary of Consumer Education Recommendations		
Ex. RDC-12	Proposed Universal Service Budget		
City of Pittsburgh *et al.* Statement No. 3-S (cosponsored with the Environmentalists)	Surrebuttal Testimony of Roger Colton		
Ex. RDC-1-S	Memorandum of Residential Mobility and the Low Income Consumer		
Ex. RDC-2-S	Prepayment Meters and Low Income Consumers		

I have also sent this document to you by e-mail at "jmoot@skadden.com". Copies of this letter are being served on all parties of record by facsimile.

Sincerely,

Roger E. Clark

Roger E. Clark
Attorney for the Environmentalists

Copies: All parties of record

FIRST JOINT STIPULATION
EXHIBIT NO. 5

HSS AND ARI
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
	Prepared Direct Testimony of Dr. Robert B. Weisenmiller, Volume I		
RBW-1	Supplemental Response to Item Nos. HSS-1-001, 21 (Supp.), etc. (corrections to Duquesne's case-in-chief)		
RBW-2	Skadden, Arps letter forwarding narrative prepared by Northbridge Group regarding discovery requests HSS-3-008 and HSS-3-009		
RBW-3	"Generating Assets," April 1995 (Duquesne study re: possible sales of its generating assets)		
RBW-4	Chart, "Best Practices Reduce Total Personnel By 45%"		
RBW-5	Duquesne Fossil Generating Business Unit, Development of a GENCO, Dec. 1996		
RBW-6	Presentation to Project Lead Team - Project Update, July 15, 1996		
RBW-7	Presentation to Project Lead Team - Preliminary Valuation and Operating Cost Allocation, August 5, 1996		
RBW-8	Presentation to Project Lead Team - Asset Valuation and Strategic Options, August 16, 1996		
RBW-9	Presentation to Project Lead Team - Regulatory Recommendations and GENCO Structure, Sept. 13, 1996		
RBW-10	CS First Boston, Materials Prepared for Discussion, Nov. 21, 1996		
RBW-11	Charts, "Generating Costs For Duquesne"		
RBW-12	Table, To Go Cost of Generation, etc.		
RBW-13	Chart, Duquesne System Lambda, 1996		
RBW-14	Duquesne Response to Interrogatory No. HSS-1-72/73 (revised) and attachments (re: RFP bids, etc.)		
RBW-15	Duquesne letter regarding RFPs and bid forms		

Exhibit	Description	Date Identified	Date Admitted
RBW-16	Duquesne Response to Interrogatory No. HSS-1-016 (revised) (Testimony of D.W. Marshall, Investigation into Electric Power Competition, I-940032, filed Nov. 6, 1995)		
RBW-17	West Penn Power Docket No. R-00973981 Interrogatories (AYP Energy, Inc.'s RFP bids)		
RBW-18	Duquesne Response to Interrogatory No. OCA-3-016 (current ECR charge is 12.822 mill/kWh)		
RBW-19	Duquesne Response to Interrogatory No. HSS-1-026		
RBW-20	Excerpts from Alexander Galatic, Written Rebuttal Testimony on Behalf of West Penn Power Company		
RBW-21	Duquesne's Response to HSS-1-015 (revised) – **Protected Materials**		
RBW-22	Duquesne's Response to HSS-1-015 (revised) – **Protected Materials**		
RBW-23	Duquesne Response to Interrogatory No. OCA-3-001 (credit rating reports)		
RBW-24	Table, Utility Comparison		
RBW-25	Chart, Ranking of DLCo & APS Coal Plants with PJM Coal Plants, Based on Total Expenditures per Net MWh - 1995		
RBW-26	A Report on The Review of Potential Stranded Costs, Duquesne Light Company, August 1997		
RBW-27	Duquesne Response to Interrogatory No. DH-1-28 (settlement agreement between GE and *inter alia*, Duquesne)		
RBW-28	Executive Summary, Duquesne Light Company (1996 rating agency presentation)		
RBW-29	Tables, DQE 12-month Results; Continued Earnings and Dividend Growth; Consistent Financial Performance – NatWest Securities Mid-Atlantic/New England Utility Seminar, Sept. 23, 1997		
RBW-30	Duquesne Financial, Sales and Operating Information (1996 rating agency presentation)		
RBW-31	Duquesne Rating Agency Presentation, August 1996		

Exhibit	Description	Date Identified	Date Admitted
RBW-32	Duquesne Response to Interrogatory Nos. HSS-3-01 and HSS-3-02 (explanation of ratepayer benefits)		
RBW-33	Duquesne Response to Interrogatory No. OCA-1-007 (regulatory assets and decommissioning expenses)		
RBW-34	Duquesne Response to Interrogatory No. HSS-1-044 (regulatory assets in rate base)		
RBW-35	Duquesne Response to Interrogatory No. HSS-1-043 (Supp.) (authorization for claimed regulatory assets: excerpts from 860378 order)		
RBW-36	Duquesne Response to Interrogatory No. HSS-1-043 (Supp.) (authorization for claimed regulatory assets: excerpts from R-870222 order)		
RBW-37	Duquesne Response to Interrogatory of David Hughes Set I, Item No. DH-1-10 (excerpts from Duquesne's 1995 and 1995 Form 10-Ks)		
RBW-38	Duquesne Response to Interrogatory No. HSS-1-030 (revised) (excerpts from Ft. Martin amended proposal re: deferred costs)		
RBW-39	Excerpts from Duquesne 1996 Form 10-K		
RBW-40	Excerpts from Duquesne Response to Interrogatory No. DH-1-18 (Feb. 17, 1983 letter to Duquesne Shareholders)		
RBW-41	Duquesne Response to Interrogatory No DH-1-10 (excerpts from Duquesne's 1995 and 1995 Form 10-Ks)		
RBW-42	Duquesne Response to Interrogatory No. OCA-1-040 (Brunot Island rate base treatment)		
RBW-43	Duquesne Response to Interrogatory No. OCA-3-042 (Brunot Island and Phillips units--no plans to return cold service units to service)		
RBW-44	Duquesne Response to Interrogatory No. ENV-1-024 (excerpts from Sept. 1997 Integrated Resource Plan)		
RBW-45	Duquesne Response to Interrogatory No. HSS-3-03 (excerpts from Pennsylvania PUC Order in P-900485)		
RBW-46	Duquesne Response to Interrogatory No. OCA-1-018 (future use or sale of Brunot Island and Phillips units)		

Exhibit	Description	Date Identified	Date Admitted
RBW-47	Duquesne Response to Interrogatory No. OCA-1-008 (Chart, Annual Amortization Amounts)		
RBW-48	Table, All-In Costs of Combined Cycle Plants		
RBW-49	Duquesne Response to Interrogatory No. HSS-1-091 (Schnitzer's natural gas market price forecasts)		
RBW-50	Tables, Wellhead (lower 48) Natural Gas Price Projections (1995)		
RBW-51	Duquesne Response to Interrogatory No. HSS-2-38 (gas transportation costs forecast)		
RBW-52	Duquesne Response to Interrogatory No. HSS-2-34 (2.5% inflation factor sources)		
RBW-53	Table, Percent Change from Previous Period--GDP PPD		
RBW-54	Excerpts from Duquesne Resource Planning Report, July 1, 1996		
RBW-55	Presentation to Project Lead Team - Preliminary Recommendations, August 30, 1996		
RBW-56	Presentation to DQE, Inc. Regarding the Sale of Certain Generating Assets, June 16, 1995		
RBW-57	Table, Comparison of Estimates of Market-Clearing Prices		
	Prepared Surrebuttal Testimony of Dr. Robert B. Weisenmiller, Volume IV		
RBW-58	Presentation to Gary Brandenberger - Draft Presentation for Fall Planning Council, Sept. 5, 1996 (Metzler)		
RBW-59	Presentation to Gary Brandenberger - Draft Presentation for Fall Planning Council, Sept. 5, 1996 (Metzler)		
RBW-60	Petition of Duquesne to discontinue normal operation of Phillips Power Station, South Heights, Pennsylvania		
RBW-61	Calpine Acquires 120 MW Gas-Fired Facility, Non-Nuclear Electric Power Generation, etc.		

Exhibit	Description	Date Identified	Date Admitted
RBW-62	Errata to Prepared Testimony of Dr. Robert B. Weisenmiller		

RBW-62

ERRATA

The following corrections should be made to the testimony of Dr. Robert B. Weisenmiller:

(a) Prepared Direct Testimony:

1. At page 41, line 12, after "effect." insert "See Exh. RBW-18."

2. At page 118, line 16, change "West Penn's" to read "Duquesne's".

3. At page 123, line 5, change "EIA, Penelec, PECO, AYP" to read "EIA, Penelec, AYP".

(b) Prepared Surrebuttal Testimony:

1. At page 1, add the following entities to the list of HSS and ARI members sponsoring Dr. Weisenmiller's testimony:

South Hills Health System (all locations)
University of Pittsburgh Medical Center (all locations)

FIRST JOINT STIPULATION
EXHIBIT NO. 6

SYSTEM COUNCIL U-10, INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	*Description*	*Date Identified*	*Date Admitted*
IBEW Statement No. 1	**Rebuttal Testimony of Timothy Moran** **(Generation suppliers should not be allowed to provide metering, billing, and other customer service functions. Duquesne should not be required to sell or shut down any of its power plants.)**		
Schedule TM-1	Rebuttal testimony of William Schmitt from the PP&L Restructuring Case		
Schedule TM-2	Number of Duquesne Light Company employees by year from 1986-1996 (HSS-2-017)		
Schedule TM-3	Duquesne Light Company Distribution of Salaries and Wages for 1996 (FERC Form 1, pages 354-355)		

FIRST JOINT STIPULATION
EXHIBIT NO. 7

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
DUQUESNE LIGHT COMPANY

Application for Approval of a Restructuring Plan
Pursuant to 66 Pa. C.S. §2806(d)
Docket No. R-00974104

INDEX OF MAPSA TESTIMONY AND EXHIBITS

Exhibit	***Description***	***Date Identified***	***Date Admitted***
MAPSA Statement No. 1	Direct Testimony of Whitfield A. Russell (Addressing competitive issues raised by Duquesne's Customer Choice Plan)		
Exhibit WAR-1	Whitfield A. Russell Curriculum Vitae		
Exhibit WAR-2	Chart Showing Monthly Firm Available Transmission Capacity for Allegheny Power		
Exhibit WAR-3	1996 Duquesne System Lambda		
Exhibit WAR-4	Calculation of Duquesne CGC Based Upon 1999 CCGT [1]		
Exhibit WAR-5	ERRATA to Prepared Direct Testimony of Whitfield A. Russell		
MAPSA Statement No.1-SR	Prepared Surrebuttal Testimony of Whitfield A. Russell		

FIRST JOINT STIPULATION
EXHIBIT NO. 8

INDEX OF TESTIMONY AND EXHIBITS
OF INTERVENOR NEV EAST, L.L.C.,
SUBMITTED PURSUANT TO SIXTH INTERIM ORDER

Statement/Exhibit	*Description*
NEV Statement No. 1	Direct Testimony of David Magnus Boonin (regarding the unbundled rate for generation, CTC methodology, unbundling of all tariffs, and billing and metering issues)
Exhibit NEV/DMB #1	Resume of David Magnus Boonin
Exhibit NEV/DMB #2	Chart setting forth methodology for reconciling the CTC
NEV Statement No. 2	Direct Testimony of Nancy I. Day (regarding the importance of unbundling distribution services to the formation of a competitive energy market)
Exhibit NEV/NID #1	Resume of Nancy I. Day

*Pursuant to the December 30, 1997 Order of Administrative Law Judge John H. Corbett, Jr. and agreement of the parties, the foregoing testimony will be admitted into the record by stipulation and without cross-examination.

FIRST JOINT STIPULATION
EXHIBIT NO. 9

OFFICE OF SMALL BUSINESS ADVOCATE
INDEX OF TESTIMONY AND EXHIBITS

Statement/Exhibit	Description
OSBA Statement No. 1*	Direct testimony and Exhibit of Brian Kalcic (recommending adjustments in Duquesne's distribution-related revenue requirements and its rate redesign plan, and offering comments on Duquesne's proposed Phase-In plan.)
OSBA Exhibit No. 1* (with Schedules BK-1, BK-2 and BK-3)	Schedules summarizing Duquesne's functionalized revenue requirements including OSBA's proposed adjustments
OSBA Statement No. 1R**	Rebuttal Testimony and Exhibit of Brian Kalcic (addressing issues raised by other witnesses regarding the pace of stranded cost recovery, the determination of CTC, allocation of universal service costs and proposals for phase-in)
OSBA Exhibit No. 1R** (Schedule BK-1R)	Amortization of DII recommended stranded costs over 4 versus 7 years
OSBA Statement No. 1S***	Surrebuttal Testimony of Brian Kalcic (responding to Co. witness Lahtimen regarding use of realized rather than claimed rate of return for unbundling rates and DII witness Baron regarding allocation of CTC revenue responsibility to all classes)

* Served November 7, 1997
** Served December 2, 1997
*** Served December 11, 1997

FIRST JOINT STIPULATION
EXHIBIT NO. 10

OFFICE OF CONSUMER ADVOCATE
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	*Description*	*Date Identified*	*Date Admitted*
OCA Statement No. 1	**Direct Testimony of Matthew I. Kahal (Evaluation of Duquesne's proposed stranded cost plan)**		
Schedule MIK-1	OCA Overall Stranded Cost Summary		
Schedule MIK-2	Excess Pre-Tax Earnings During Transition Period		
Schedule MIK-3	Retail Rate Comparisons for 1996		
Schedule MIK-4	DRI vs. Duquesne Inflation Rate Forecasts		
Schedule MIK-5	Derivation of the Discount Rate		
Schedule MIK-6	Productivity Enhancement Savings		
Schedule MIK-7	PECO and West Penn Power Life-Extension Costs for Coal Plants		
Schedule MIK-8	Cheswick Life Extension Costs and Net Benefits		
Schedule MIK-9	Generation Net Merger		
OCA Statement No. 1S	**Surrebuttal Testimony of Matthew I. Kahal (Response to Rebuttal Testimony on stranded cost issues)**		
Schedule MIK-1 UPDATE	OCA Overall Stranded Cost Summary		
Schedule MIK-6 UPDATE	Productivity Enhancement Savings		
Schedule MIK-10	Projected Pre-Tax Operating Losses During Transition		
OCA Statement No. 2	**Direct Testimony of Douglas C. Smith (Market Price Analysis)**		
Exhibit DCS-1	Resume of Douglas C. Smith		
Exhibit DCS-2A	New Combined Cycle Non-Fuel Cost Assumptions		

Exhibit DCS-2B	New Combustion Turbine Non-Fuel Cost Assumptions		
Exhibit DCS-3	Spring 1997 DRI Fuel Price Escalation Rates		
Exhibit DCS-4	APS-DQL Market Price Estimate		
Exhibit DCS-5	DQL Weighted Generation Price		
OCA Statement No. 2S	**Surrebuttal Testimony of Douglas C. Smith (Response to rebuttal testimony on market price issues)**		
OCA Statement No. 3	**Direct Testimony of Thomas S. Catlin (Regulatory asset issues, nuclear and fossil decommissioning, taxes and other transition costs)**		
Schedule TSC-1	Summary of Regulatory Assets and Other Transition Expenses		
Schedule TSC-2	Summary of Decommissioning Funding Requirements as of 12/31/98		
OCA Statement No. 3S	**Surrebuttal Testimony of Thomas S. Catlin (Response to rebuttal testimony on prescribed nuclear outage costs and unamortized debt costs)**		
OCA Statement No. 4	**Direct Testimony of Lee Smith (Rate design, unbundling, cost allocation, and CTC design)**		
Exhibit LS-1	Summary of Qualifications and Experience		
Exhibit LS-2	Calculation of Market Price		
Exhibit LS-3	1996 Administrative & General Expenses		
Exhibit LS-4	Retail Cost of Service CTC Proposal		
Exhibit LS-5	Retail CTC/Calculation of Levelized CTC		
Exhibit LS-6	Unbundled Rate Design Residential - Rate RS		
OCA Statement No. 4S	**Surrebuttal Testimony of Lee Smith (Response to testimony on treatment of ancillary service costs, line losses, A&G adder, and rates of return)**		
Exhibit LS-7	Revised LS-4 (Retail Cost of Service)		

Exhibit LS-8	Revised LS-2 (Calculation of Market Price)		
Exhibit LS-9	Revised LS-5 (Retail CTC)		
Exhibit LS-10	Revised LS-6 (Unbundled Rate Design)		
OCA Statement No. 5	**Direct Testimony of Barbara Alexander (Consumer education and consumer protection issues)**		
Exhibit BA-1	Resume of Barbara Alexander		
Exhibit BA-2	Vermont Consumer Information and Education Plan		
Exhibit BA-3	California Statewide Consumer Education Plan		
Exhibit BA-4	Massachusetts Department of Public Utilities Code of Conduct		
OCA Statement No. 5R	**Rebuttal Testimony of Barbara Alexander (Response to testimony on provision of generation services to default customers and supplier-only bill option)**		
OCA Statement No. 5S	**Surrebuttal Testimony of Barbara Alexander**		
Exhibit BA-S-1	Executive Summary of New Hampshire Pilot Program Survey Report		
Exhibit BA-S-2	CAPUC Fact Sheets on Consumer Education Plan		
Exhibit BA-S-3	Recommendations of the Maine Consumer Education Advisory Board		
OCA Statement No. 6	**Direct Testimony of Nancy Brockway (Universal Service Issues)**		
Exhibit NB-Duq-1	Resume and Curriculum Vitae of Nancy Brockway		
Exhibit NB-Duq-2	Duquesne Estimation of Potential CAP Eligible Customers		
Exhibit NB-Duq-3	Universal Service Costs - Per kWh Allocator		
Exhibit NB-Duq-4	Development of Non-Production Revenue Allocator		

OCA Statement No. 6S	**Surrebuttal Testimony of Nancy Brockway (Universal Service Issues)**		

FIRST JOINT STIPULATION
EXHIBIT NO. 11

Pennsylvania Public Utility Commission
v.
Duquesne Light Company

Docket No. R-00974104

Index* of OTS Testimony And Exhibits Not Yet Admitted

Exhibit	Description	Date Identified	Date Admitted
OTS Statement No. 3	Direct Testimony of Paul M. Yarolin (concerning Universal Service and rate unbundling)		
OTS Cross Examination Exhibit No. 3	On-the-Record Data Request Response (O'Brien Number 1) concerning the difference in balances associated with cold reserve units		
OTS Cross Examination Exhibit No. 4	On-the-Record Data Request Response (O'Brien Number 4) concerning recovery of decommissioning costs		
OTS Cross Examination Exhibit No. 5	On-the-Record Data Request Response (O'Brien Number 5)** concerning recovery of decommissioning costs		

* OTS reserves the right to request admission of additional exhibits upon receipt of all responses to On-the-Record Data Requests.

** OTS has requested that this On-the-Record Data Request Response be supplemented to properly respond to the request.

FIRST JOINT STIPULATION
EXHIBIT NO. 12

PENNSYLVANIA RETAILERS ASSOCIATION
INDEX OF TESTIMONY

EXHIBIT	DESCRIPTION	DATE IDENTIFIED	DATE ADMITTED
PRA Statement No. 1	Direct Testimony of Chris K. Albrecht (Phase-in Procedure for retail competition)		

NEV STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY OF DAVID MAGNUS BOONIN

Regarding Generation Rate, CTC's, Unbundling of Tariffs and Billing Issues

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

A. My name is David Magnus Boonin. I am Executive Vice President of NEV East, L.L.C., doing business as New Energy Ventures - Mid-Atlantic ("NEV"). My business address is 1845 Walnut Street, Suite 2525, Philadelphia, PA 19103.

Q. Please describe NEV East.

A. New Energy Ventures - Mid-Atlantic is the name under which NEV East, L.L.C. does business in Pennsylvania. NEV is an Arizona limited liability corporation. NEV organizes and manages a buyers' alliance for retail energy. Our business is saving our members money on their energy bills. In this proceeding and elsewhere, we work for our members and potential members. We have offices in California, Boston, New York and Philadelphia. We are a certified FERC Power Marketer and are a registered provider of retail electricity in California. NEV is licensed in Rhode Island and is a member of the New England Power Pool. We are a licensed alternative supplier in Pennsylvania.

Q. Please describe your education and experience.

A. Since graduation from The Wharton School in 1973, I have spent almost my entire career in the fields of utility planning, management and policy. A copy of my resume is attached as NEV/DMB Exhibit #1. Some of my positions prior to joining NEV including serving as Chief Economist for the Pennsylvania Public Utility Commission, Commissioner and Executive Director of the Philadelphia Gas Commission and Supervisor of Economic and Energy Forecasting for a major electric utility. I also headed my own consulting practice. Among the issues I addressed on behalf of my clients was the issue of the restructuring of the utility industry. I have had extensive experience in designing adjustment clauses under

industry. I have had extensive experience in designing adjustment clauses under section 1307 of the 66 Pa.C.S.A. I have also presented or had published numerous papers and have testified before regulatory and legislative bodies on utility and regulatory issues.

Q. What is the purpose of your testimony?

A. The main purpose of my testimony is to present an approach for the unbundling of the cost of generation which is consistent with Act and allows for the development of a competitive market for electricity. In addition, I will address the need to make tariffed benefits available to all customers regardless of their chosen generation supplier, as well as the billing issue of the definition of the term customer in the deregulated market.

UNBUNDLED RATE FOR GENERATION

Q. Please summarize your approach to establish an unbundled price for generation.

A. I propose that the unbundled price for generation is to be determined by the market. This is necessary in order to make choice a reality for retail customers while treating all affected parties equitably. In this newly competitive world, generators will be afforded the opportunity to sell their power on a power exchange. The price for generation should be determined by the market-clearing price of the power exchange, adjusted for the costs of retail delivery. To make this comply with rate cap, I also recommend that the unbundled charge for electricity and the CTC always be kept in balance so that the total of the two never varies.

Q. You mentioned that the unbundling methodology should comply with the law. What does the statute state?

A. Section 2802 (14) of the statute states in part:

> "The generation of electricity will no longer be regulated as a public utility function."

Section 2804(3) of the statute states in part:

> "The Commission shall require the unbundling of electric utility services, tariffs and customer bills to separate the charges for generation, transmission and distribution."

Section 2807(E)(3) of the statute states:

> "If a customer contracts for electricity and it is not delivered or if a customer does not choose an alternative electric generation supplier, the electric distribution company or the Commission-approved alternative supplier shall acquire electric energy at prevailing market prices to serve that customer and shall fully recover all reasonable costs." (emphasis added)

Q. Why is Section 2807(E)(3) important?

A. Section 2807(E)(3) determines the price the electric distribution utility (EDU) may charge for generation to any user other than those who have chosen an alternative generation supplier. This section sets forth that the EDU (or someone else designated by the Commission) shall provide this service at "prevailing market prices" and be fully compensated. As the price of generation is otherwise deregulated by the Act and is to be unbundled, it is precisely this language which

sets the unbundled price of generation which may be charged by the EDU.

Q. You also mentioned that the unbundled price of generation should be based on certain market principles. Please explain.

A. In practice, the price of generation varies from hour to hour across the year. Fixed prices established through regulation, even those with demand charges and/or time-of-use pricing will only reflect the actual price of generation by happenstance. This is the fundamental practice under the existing regulatory paradigm. In the new competitive environment, electricity is being turned into a commodity whose price shall vary depending on market conditions. Therefore, the appropriate unbundled price of generation should also vary with the market and not be fixed.

Q. Why is a variable versus a fixed price of generation more appropriate?

A. For the Commission to estimate and establish a fixed price for generation in an unbundled, full service tariff it must make and lock in numerous assumptions. Generally, when estimating a price, "normal" assumptions are made about weather, fuel, prices, economic conditions, supply availability, etc. These assumptions are for extended periods. There is almost no possibility that these normal estimated costs will produce a price at prevailing market rates at every time let alone at most times.

In contrast, a variable price can change with market conditions and frees the Commission from the impossible task of accurately predicting the prevailing market price of generation. This approach is also consistent with the intent of the legislation which is to deregulate the price of generation, not to reestablish a regulated price of generation on a different concept than historical rate base regulation.

Duquesne Light agrees that a market-based CTC is superior to a fixed CTC, but, as I discuss below in detail, Duquesne Light has proposed a less accurate and efficient method of determining the market price.

Q. What is your proposal for the unbundling of generation in the EDU's tariff?

A. I propose inserting the following language in each tariff for individual classes of customer:

> "The unbundled rate for generation shall be established by the power exchange market clearing bid price for generation, fully adjusted for ancillary services necessary to convert wholesale generation into reliable, deliverable retail power at market determined or FERC approved prices which may be required by the independent system operator (ISO), including but not limited to, capacity, spinning reserves, load balancing and as further adjusted for losses associated with the voltage level of delivery and location."

This language would be further enhanced after the final establishment of a power exchange (PX) and/or independent system operator (ISO) and their establishment of final governing rules. As the establishment of an ISO and PX is necessary for retail competition to function, waiting to enhance this language should not in and of itself cause significant delays.

This language establishes the basis for determining the prevailing market price for retail generation at any point in time.

To understand this approach it is necessary to understand several concepts. First that power exchange establishes the wholesale price for energy by establishing a market price for electricity based on wholesale bids. Second, there are services,

such as load balancing, spinning reserves, etc. which have costs, which are necessary to convert this wholesale energy into retail electricity. Third, losses associated with the transmission and distribution of electricity may cause the retail price for power to vary depending on the level of voltage delivery. Fourth, at certain times of the year, even within an EDU's service territory, locational price differences may occur, depending on physical limitations and/or FERC pricing decisions.

Q. Please explain why the power exchange price establishes the wholesale price for electricity.

A. The PX will continually solicit bids from wholesalers to meet current demands. The highest price bid used during a period (probably hourly) will set the prevailing wholesale market price for energy at that time. The process of matching supply and demand will be repeated continually during the day with a new wholesale market prevailing rate established (probably hourly). This bid process will replace the current economic dispatch system currently used by many utilities and power pools. It allows all willing suppliers to bid for the right to supply the demand that exists, excluding what has been met by bilateral contracts. There may be exceptions for plants that are dispatched for reasons other than price (e.g. system balancing). These exceptions will be known and can be treated like other ancillary services needed to convert wholesale service into retail service.

Q. Please explain why and how these services need to be adjusted to reflect reliable, deliverable retail electricity.

A. The supply and demand of electricity are subject to many stochastic events. Power plants are forced off-line. Customers turn electricity consuming equipment on and off unexpectantly and randomly. Because of this, it is not enough to use the wholesale PX price as the total power exchange price. It is also necessary to

include costs associated with converting that energy into reliable retail electricity. The ISO shall determine rules of what ancillary services a supplier must provide. These services may include but are not limited to: capacity, spinning reserve and load balancing. These services are the types that are generally necessary to convert wholesale power into reliable electricity. These services will either be priced at a set price by the ISO and FERC or through the market (my preferred approach).

Q. Please discuss the adjustments that are necessary due to voltage differences.

A. Power delivered at declining voltages experience greater losses. An adjustment factor should be applied to each voltage delivery level to reflect these differences.

Q. Please discuss the adjustments that are necessary due to the location of the customer.

A. Sometimes, due to transmission limitations, power prices within a power exchange may differ at different locations. If the ISO identifies such limitations and establishes the need to have different pricing in different regions, then individual prevailing market clearing prices may need to be established for certain sub-regions at certain times.

Q. Why is this adjusted power exchange price an accurate proxy for prevailing market prices?

A. This is the way goods and services in the market are usually priced. The power exchange adjusted for retail delivery starts with a prevailing wholesale market price and adds the costs necessary to convert it to the retail service.

Q. Please describe how prevailing wholesale market prices would be converted to

prevailing retail market prices.

A. Starting with wholesale energy and capacity costs, a system load factor could be applied to transform the capacity into a kWh based price. Energy needs to be adjusted for line losses. Similarly, ancillary charges at market prices must be added. An A&G component would also be appropriate. Finally a tax true-up should be applied. After a system number is developed, a number for each rate class, following the same methodology should be calculated.

Q. Under your proposal, how often will the prevailing market price change?

A. It will change as often as the components discussed above cause a change. Practically, I see the prevailing market price changing hourly, much as today's power pool price (or system lambda) changes today.

Q. Given that the prevailing market price may be changing hourly, what type of metering will be necessary?

A. That will be up to the individual supplier and the ISO rules of load balancing. In general, I anticipate that hourly meters will be necessary for larger loads, regardless of whether the generation supplier is the EDU or another supplier. Small loads, such as residential and small commercial customers may be able to be metered as currently done, if the ISO permits the use of a standard load curve(s) for load balancing purposes.

Q. How do you anticipate customers being billed?

A. Each individual customer with hourly meters would be billed based upon the full prevailing retail market price for each kilowatt consumed in that hour. Demand

billing and ratchets should become unnecessary following this approach for generation.

Capacity charges would be charged during the hour that the customer imposed the need. Small customers without hourly meters who have an acknowledged and approved load shape would be billed based upon the their kWh usage spread over the load shape, using the prevailing market prices at the time. Customers who do not have approved load shapes and do not have hourly meters would be charged for unallocated imbalances, as reflected for their reliance on the ISO rather than their own supplies. This creates de facto hourly pricing.

Q. Do these load shapes need to be determined at this time?

A. No. I believe this would be premature. The Commission should recommend them after the ISO indicates a willingness to address load imbalance responsibilities based upon load shapes for some subset of customers.

Q. Given the variable nature of your proposed approach to unbundling generation, how will you have your approach comply with the rate cap?

A. I propose keeping the total of the unbundled price of generation and the generation related portion of the CTC constant. If the prevailing market price increases so does the unbundled charge for generation with an equal decrease to the generation portion of the CTC.

Q. Why is this appropriate?

A. Under most approaches to determining stranded costs; there is a relationship between the prevailing market price for generation and the competitive transition

charge. -All else being equal, if one were to assume an increase in the value of generation because the market price of generation increased, then the stranded costs would decrease by the same amount. Likewise, if the market price of generation were to decrease, the value of the generation would decrease and stranded costs would increase.

Stranded costs are the core of the calculation of the Competitive Transition Charge (CTC). At a particular point in time (eliminating discounting and levelization) there is a one to one relationship between a change in the value of generation and an opposite but equal change in stranded costs.

Q. In general, how would this work?

A. Because of this one to one relationship, it is recommended that in establishing the unbundled rates for generation and CTC that the Commission follow the following protocol.

- Determine stranded cost, the CTC and ITC for each rate class as appropriate.

- Stranded costs, the CTC and ITC should be split between generation-related and non-generation related costs.

- Explicitly determine the related underlying assumed market price for generation associated with the generation portion of the CTC for each rate class. The price of generation could be levelized, but it is recommended that it be disaggregated at least by year.

- The EDU would compare the average weighted prevailing market price for generation for each customer class for the billing period with the underlying

assumed market price for generation.

- The generation related portion of the CTC would then be adjusted so that the total of the adjusted CTC and the prevailing market price for the period would always be equal to the base CTC and underlying assumed price of generation.

This approach is consistent with section 2804(4)(II), which joins the CTC, ITC and the unbundled price of generation.

Q. Please explain why and how you are splitting the CTC.

A. I recommend that the Commission split the CTC into two categories, which I will loosely term "generation related" and "non-generation related" depending on whether the costs vary with the market price of energy. ("Generation-related" costs are those that vary with the value of generation while "non-generation related costs" do not directly vary with the value of generation.) This allows for the generation-related portion of the CTC to be used as offsets to variation in the prevailing market price as discussed above. This charge should be set only on a kWh basis. Hourly allocations of generation related costs should negate the need for demand charges and ratchets. I do not have an opinion at this time on the rate design for the non-generation related portion of the CTC.

Q. Would you please provide a simple example of how your proposal would work?

A. Yes. Assume for purpose of illustration that the base generation related CTC established by the Commission is 1.5 cents/kWh and the associated estimated market price/value of generation is 2.9 cents per kilowatt-hour for a total of 4.4 cents. Assume also that in a given month the actual prevailing market price is 2.7 cents. This is 0.2/kWh cents less than the estimated market price that is the basis

for determining the CTC. The CTC would therefore be increased by the same amount for bills rendered for that period or to 1.7 cents per kilowatt-hour. Under either case the combined total will still be 4.4 cents/kWh.

If the opposite were true and the prevailing market price were to exceed the estimated market value of generation, then the CTC would be decreased.

This self balancing process assures that the generation related charges are always in compliance with the rate cap provisions of the Act.

Q. Have you considered how the Commission would go about reconciling the ITC and CTC consistent with sections 2808(F) and 2812(B)(5) of the Act, given your variable CTC methodology?

A. Yes.

Q. Why is it necessary and appropriate for the Commission to establish a reconciliation methodology at this time?

A. The Commission in its April 10, 1997 order on periodic adjustment of the CTC and the ITC stated that "only during the course of the evidentiary hearings can such matters as the appropriate CTC/ITC calculation and reconciliation methodology be determined as well as the appropriate format, content and necessary supporting information associated with the annual CTC reconciliation's and periodic ITC adjustments."

Q. Please summarize your reconciliation methodology.

A. I propose a reconciliation method which individually reconciles the Competitive

Transition Costs associated with generation and non-generation related costs. Non-generation costs would only be reconciled based on changes in absolute levels of recovery caused by variations between forecasted and actual sales. Generation related costs would also be reconciled for variations in sales but only after an adjustment is made to the required level of amortization to reflect changes in the prevailing market price. I have also proposed, as a general rule, deferring adjustments for over or undercollections to the end of the transition period.

Q. Have you provided a more detailed description of your proposed reconciliation methodology?

A. Yes. It is attached as NEV/DMB Exhibit #2.

Q. In your proposal, does it matter whether the sales are billed directly by the EDU or whether the EDU provided the generation service?

A. No. All customers in a given rate class should pay the same CTC rate(s).

Q. How does this work with a utility like Duquesne Light who is trying to recover its CTC partially on an energy and partially on demand basis?

A. Non-generation related costs could still be recovered in a fashion similar to Duquesne Light's proposal. As I stated earlier, I have not yet developed an opinion in the appropriate rate design for this item, nor is it germane to my proposal. All generation related charges would be recovered on a kWh basis. Actual or imputed load shapes would assign actual prevailing rates to each customer. Demand ratchets would be eliminated for these portions of these services as would cross subsidization for generation. Customers would pay only for the load the actually placed on the system.

Q. Would the CTC change for all customers or only those receiving full services from the EDU?

A. The CTC would change for all customers.

Q. Why should the CTC change for all customers based upon prevailing market prices for generation?

A. The CTC is a charged being imposed on customers regardless of whether they stay with the EDU or seek energy services form an alternative supplier. The CTC should be the same for similar customers who are served by the utility at the prevailing market rate or by an alternative provider at a market-determined rate.

Q. How does your proposal for establishing a prevailing market price for generation compare with those of Duquesne Light?

A. Although Duquesne Light recognizes that the market should determine the CTC, Duquesne Light's plan does not permit the market to do so. Under Duquesne Light's plan, the "market price" would be determined by an artificial bidding process controlled by Duquesne Light's terms, including parameters imposed by Duquesne Light relating to the amount and duration of energy supply purchased, the minimum bidding price, and the criteria for selecting the winning bidder. The plan purports to be market-driven, but it is in fact driven by artificial parameters chosen by Duquesne Light.

As I described earlier, the accurate market price will be readily determined by the power exchange market clearing price for generation, consistent with final governing rules established by the ISO. There already will be a genuine market mechanism to determine the market price. Duquesne Light has offered no reason why this

mechanism should be replaced with an artificial bidding process governed by Duquesne Light.

Moreover, under Duquesne Light's plan, a final determination of the market price would be deferred until 2003. Duquesne Light has offered no sound basis for waiting until 2003 to make this determination when an on-going, self-correcting gauge of the market price can easily be implemented. There are, however, important reasons for not waiting until 2003 to make a final market price determination. First, consumers should not bear the risk of paying a higher CTC than is appropriate during the intervening five years. Second, the final determination Duquesne Light proposes would be in a private, presumably closed, arbitration proceeding, and will therefore prevent the many interested parties to this proceeding from being heard, including alternative generation suppliers. The approach I have described above, in contrast, would be self-implementing based on the market, and would not require an adjudication in either a private arbitration proceeding or any other forum, of what the artificial, so called "market" price should be.

Q. Is your approach consistent with the statute and Commission orders and regulations?

A. As discussed in more detail above, yes.

Q. Can this approach be used for any utility?

A. Yes.

Q. Will people know the price of electricity before they consume it?

A. Yes. Customers electing to stay with the EDU for full service would know the price of generation before it is consumed although there may be shifting between the subparts of the CTC and generation.

Q. Does the proposed approach guarantee the recovery of allowed stranded costs?

A. Yes, as annually reconciled to reflect actual market conditions. It is, therefore, a FAR more accurate approach than one which is based upon a one time estimate of market prices.

Q. Do other sections of the statute support the idea of a variable price of generation?

A. Yes. Section 2808(c)(4) provides:

> "In determining the level of transition or stranded costs that an electric utility may recover through the competitive transition charge, the Commission shall apply the following principles:
>
> (4) . . . **During the transition period**, electric utilities **shall** have the duty to mitigate generation related transition or stranded costs to the extent practicable." (emphasis added)

It is apparent that under Section 2808(c)(4), mitigation of stranded costs must continue throughout the transition period. My proposal makes the mitigation automatic. That is, if the market price of generation in any period is higher than the amount used to calculate the stranded cost, the excess revenues will be used directly to mitigate stranded costs by being applied to reduce the CTC for the period. The statute says that utilities "shall have the duty to mitigate stranded costs" during the transition period "to the extent practicable." My proposal shows how such

mitigation is practicable.

Q. How would securitization work under your proposal?

A. It should be possible to securitize bonds through the ITC plus offsetting revenue associated with the increased value of generation. These dual revenue sources could both be pledged.

Q. You have developed a detailed approach for unbundling. How should the final tariffs be developed?

A. I recommend that the Commission direct Duquesne Light to submit tariffs consistent with this approach and with the Commission's findings. A CTC (which could be split between generation and non-generation) will need to be provided by Duquesne Light as compliance filing with the Commission's final order. The Commission should explicitly state for each class of customer the assumed prevailing market price(s) for generation used in developing its stranded cost findings so that the adjustment mechanism I propose can be followed. A good first step would be to have Duquesne Light complete the table I have laid out in my Exhibit #2.

PORTABILITY OF TARIFFED BENEFITS

Q. Must tariffed benefits be portable regardless of generation supplier?

A. Yes. Any utility which offers any rate discount must make that same discount available to any customer regardless of their chosen generation supplier.

Q. Why is this important?

A. First this provides a level playing field. Utilities who offer economic development discounts, time-of-use discounts, low-income bill discounts, interruptible service discounts, etc. must make these services and discounts available to all customers, regardless of generation supplier. Second, failure to do so would be in violation of the Act which calls for rate unbundling for all customers.

BILLING AND THE DEFINITION OF A CUSTOMER

Q. Please summarize your testimony in this area.

A. Many customers have service on multiple meters throughout an EDU's service territory. These customers are currently discriminated against when compared to customers with similar loads served through a single meter. I propose that alternative generation providers be permitted to treat these customers as a single service for purposes of billing for transmission and CTC related charges.

Q. Why did you exclude generation from your earlier response?

A. The price of generation is deregulated and the EDU already has the right to issue a customer a bill for its generation services on a consolidated basis. No Commission action is required.

Q. Why did you exclude distribution charges?

A. This is a conservative proposal. Customers with multiple meters may impose a cost on the system that is different than a similar load from a single location associated with the distribution of the service. It is therefore recommended that these specific charges be billed as they are currently.

Q. How are transmission and CTC different from the distribution charges?

A. Transmission and CTC related charges should not change with the number of installations or meters but with the load placed on the system.

Q. Why does defining a customer by a meter discriminate against someone who receives service at multiple meters?

A. I will answer that question with an example. Assume that there is a customer with a single meter and a load of 2 MW. Assume also that there is someone else with three meters, all on the same tariff as the first customer, whose coincidental load totals to 2 MW but whose non-coincidental load is 2.5 MW. This second customer places the same type of non-distribution related load on the system but is being charged more than the first customer. All of these customers are on the same rate schedule and all have the same coincidental peak, but the multi-site customer is being irrationally discriminated against.

Q. In your example, you stated that all of the customers were on the same rate schedule. Would you make that a pre-condition of your bill consolidation proposal?

A. Yes. For administrative ease, if for no other reason, this consolidation should only be for customers of record who have multiple meters on the same rate tariff.

Q. How does this issue fit into this debate on competition?

A. Without competition this would not be as germane. Competition brings with it innovation. More and more customers will be metered such that hourly loads can be determined, a necessary request for consolidated billing. Competition also challenges the necessity of demand based billing, particularly if customers are

paying for the burden they place upon the system virtually on an hourly basis. Competition also highlights the importance of electric prices in economic competitiveness. It is no longer acceptable to shrug when the type of blatant discrimination is pointed out and say that's they best we can do. Yesterday's good enough is no longer adequate.

Q. Specifically, what is your proposal?

A. My proposal is:

1. as testified by others, alternative generation providers should be allowed to issue bills for all parts of the electric service, including those charged by the EDU;
2. that an alternative generation provider be allowed to consolidate bills for customers with multiple meters within a single rate tariff;
3. that the consolidated bill will not have any impact on the distribution charge, with the exception of unbundled services for metering, billing, collections and information which shall be competitive; and
4. that only through this modification can the Commission prevent undue competition from occurring between customers with identical loads on the same rate tariff.

Q. Does this conclude your testimony at this time?

A. Yes.

DAVID M. BOONIN

EDUCATION
Brown University, M.A. in Economics, 1976
Wharton School, University of Pennsylvania, B.S. in Economics, 1973

EXPERIENCE
New Energy Ventures, Inc., Philadelphia Pennsylvanaia
PRESIDENT, MID-ATLANTIC DIVISION, 1997 - Present
Manage NEV's Mid-Atlantic operations.

Consulting
PRESIDENT, THE BOONIN GROUP/SENIOR ADVISOR, HAGLER-BAILLY CONSULTING, 1992 1997
Provide strategic, policy and technical advice to utilities and others dealing with utility matters. Clients and assignments are diverse ranging from industries including: electric, gas, water and transportation and issues including competition, rates, restructuring, regulatory policy, etc

City of Philadelphia, Philadelphia, Pennsylvania
EXECUTIVE DIRECTOR, PHILADELPHIA GAS COMMISSION, 1991 - 1994
Managed the Commission's technical and administrative staffs. Provided policy and strategic advice to the Commissioners. Interfaced with the public including: government officials, the press, interest groups, etc.

COMMISSIONER, PHILADELPHIA GAS COMMISSION, 1988 - 1991
Regulated largest gas utility in the State and largest municipal gas utility in the nation. Performed detailed budgetary and management review and oversight.

DIRECTOR OF UTILITY AND REGULATORY AFFAIRS, 1988 - 1991
Directed City's activities addressing utility and regulatory issues including the City as a large user, the City as a provider of utility services and the quality of the City's economic and physical environment. Scope of issues spanned fixed and transportation utilities as well as the insurance industry. Worked with regulators, utilities, interest groups and legislators.

DIRECTOR OF INTERGOVERNMENTAL AFFAIRS, Office of the Mayor, 1985 - 1988
Directed the City's legislative and administrative efforts with federal, state and local government, including the activities of lobbyists and Philadelphia's Washington Office. Addressed financial, economic and utility problems facing the City.

United Illuminating Company, New Haven, Connecticut
SUPERVISOR, ENERGY DEMAND AND ECONOMIC FORECASTS, 1983 - 1985
Corporate economist for a major electric utility. Managed department responsible for forecasting the utility's energy sales and peak demand. Developed energy resource strategies

Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
CHIEF ECONOMIST, 1979 - 1983
Managed the Economics Division. Developed policy recommendations, performed research and/or testified on regulatory, energy, economic, financial, rate and environmental issues

CHIEF OF THE ENERGY IMPACT ANALYSIS SECTION, 1978-1979
Managed interdisciplinary staff and projects concerning fixed utilities and energy. Developed and assessed regulations, rate structures and economic incentives

ECONOMIST, CHAIRMAN'S STAFF, 1976 - 1978
Economic advisor to the Chairman of the Commission. Reviewed each rate case as well as other cases and offered specific recommendations on all facets of the case

United Engineers and Constructors, Inc., Philadelphia, Pennsylvania
ECONOMIST, NUCLEAR TECHNICAL STAFF, 197[illegible]
Analyzed issues relating to the costs/benefits, safety and licensing of power plants

SELECTED PROFESSIONAL ACTIVITIES

- Commissioner, Philadelphia Planning Commission (1990-1991)
- Member,Private Sector Advisory Panel on Infrastructure Financing, Senate Budget Committee (1986)
- Board Member, Energy Coordinating Agency (1988-Present)
- Energy, Environment and Natural Resources Policy Committee: National League of Cities (1990-1991)
- Community and Economic Development Committee; Pennsylvania League of Cities (1989-1991)
- Served on numerous committees and task forces, including: Electric Utility Efficiency Task Force, Pennsylvania Utility Advisory Committee, Statistical Research Committee - ECNE, Taxi Advisory Committee, Utility Consumers Council, EPRI and NEPLAN Committees

PERSONAL

- American Jewish Congress - Board Member
- B'nai Brith Anti-Defamation League - National Leadership Award 1991
- Central High School Board Alumni Association - Board of Directors
- Boy Scouts of America - Assistant Scout Master, Eagle Scout
- Born May 18, 1952, Philadelphia, Pennsylvania: Married

RECONCILIATION OF THE CTC

The Commission finds that the base stranded cost recoverable through the Competitive Transition Charge (CTC) is $_____. Of this amount $_____ is not generation related and $_____ is generation related.

The generation related portion is based upon, in part, estimated levelized value of generation of $0.0xxx cents per kWh.

The base Competitive Transition Charge is as set forth in each individual rate schedule. The CTC has been divided into non-generation and generation related components.

The CTC is designed to produce the listed amortization schedule for stranded costs, divided into non-generation and generation related costs.

COMPETITIVE TRANSITION COSTS BASE ANNUAL AMORTIZATION SCHEDULE				
Year	Total to be Amortized	Non-generation Related Costs	Generation Related Costs	Projected Sales
1999				
2000				
2001				
2002				
2003				
2004				
2005				

The CTC shall be reconciled annually consistent with section 1307(e) of 66 Pa. C.S.A. Reconciliation of over or under collections shall be collected by extending or shortening the CTC period, except as otherwise ordered by the Commission.

Non-generation related CTC shall be adjusted based upon the following formula.

$Nongen_{act} - Nongen_{amort} = E_{nongen}$

where:

$Nongen_{act}$ is the actual amount collected from all classes of customers during a year for non-generation related competitive transition charges;

$Nongen_{amort}$ is the amortization schedule for the same year for non-generation related competitive transition charges as shown in the schedule; and

E_{nongen} is the over or under collections associated with non-generation related stranded costs based upon the difference between the amortization schedule and actual collections.

This process shall be repeated annually throughout the amortization period until the total amount for non-generation related stranded costs, as shown in the table above, is collected.

Note: this methodology only produces over or undercollections of non-generation related CTC when projected sales vary from actual sales.

There shall be two types of adjustments made for generation related CTC:

an adjustment to the amortization schedule based upon differences between the base generation related CTC and the CTC based on the actual market value generation, and

an adjustment for the anticipated versus actual level of collection (similar to the adjustment for non-generation related CTC).

The first step is to adjust the amortization schedule for the year being reconciled. This shall be done according to the following formula.

$(CTC_{market} \times SALES_{projected}) - (CTC_{base} \times SALES_{projected}) = E_{amort}$

where:

CTC_{market} is the adjusted CTC charged to each class of customer to reflect the change in the value of generation from that used in the calculation of the base CTC. It is determined for each class of customer by the formula:

$$CTC_{market} = CTC_{base} - (GENVALUE_{actual} - GENVALUE_{base})$$

where:

$GENVALUE_{actual}$ is weighted average of the actual prevailing market price for generation as established in each tariff; and

$GENVALUE_{base}$ is the estimated weighted average market price of generation used to in establishing stranded costs and the related base CTC, embedded in the tariff for each class of service.

CTC_{base} is the weighted average CTC based upon projected market prices and value of generation and included in the tariff for each class of service.

$SALES_{projected}$ is the number of kWh used to determine the amortization schedule as listed in the table above.

E_{amort} is the adjustment that is made to the amortization schedule for generation related CTC to reflect the change in market conditions. This changes the total dollars which need to be collected through this portion of the CTC over the transition period.

Weighting is based upon projected kWh sales for each class of service.

After the amortization schedule has been adjusted for the prevailing market price for the period, the second step is to adjust the generation related CTC for actual level of collection according to the following formula.

$Gen_{act} - Gen_{amort.adj} = E_{gen}$

where:

Gen_{act} is the actual amount collected from all classes of customers during a year for generation related competitive transition charges;

$Gen_{amort.adj}$ is the amortization schedule adjusted for the change in the market value of generation for the same year for generation related competitive transition charges as shown in the schedule and as adjusted; and

E_{gen} is the over or under collections associated with generation related stranded costs based upon the difference between the amortization schedule and actual collections.

This process shall be repeated annually throughout the amortization period until the total amount for non-generation related stranded costs, as shown in the table above, is collected.

NEV STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY
OF
NANCY I. DAY

Regarding Billing

Q1 Please state your name and business address.

A1 My name is Nancy I. Day and my business address is as follows:

New Energy Ventures, Inc.
1000 Wilshire Boulevard, Suite 500
Los Angeles, CA 90017.

Q2 By whom are your employed and in what capacity?

A2 I am employed by New Energy Ventures, Inc. My job title is Vice President, Customer Services. I am responsible for defining the critical elements necessary to deliver competitive services to energy customers. In addition, I am responsible for the legislative and regulatory advocacy of policies and programs essential to build viable competitive energy markets. My resume is attached as Exhibit NEV/NID #1.

Q3 Please describe your background and experience in the energy services industry.

A3 From 1968 to 1995 I was employed by Southern California Gas Company, the nation's largest natural gas distribution utility. From 1990-94 I served as Vice President of Regulatory Affairs. In that capacity I was the senior officer responsible for developing and executing regulatory strategies. I directed a staff of 30 professionals responsible for obtaining the required regulatory authorizations needed to run the business. I led the company's regulatory initiatives related to the transition to competitive choice for the provision of natural gas.

Q4 What is the nature of your testimony in this proceeding?

A4 My testimony focuses on the role unbundling of distribution services plays in the formation of competitive energy markets. I will address the essential components of distribution service unbundling. Finally, I will discuss my experience in the deregulation of California's natural gas and electric services industries to the extent they pertain to the issue of service unbundling.

Q5 Why is distribution service unbundling an essential element of the restructured energy services market?

A5 The simple answer is profitability. Without the unbundling and competitive provision of distribution services new market entrants will eventually be starved out of the market. This will be the inevitable result when the margins on the sale of electricity are too small to support the new market entrant's service delivery overheads. In contrast, the utility service providers' costs for provision of these overheads are imbedded in the utility's distribution revenue requirement and the utility does not have to compete for the delivery of those services. This creates an improper and unfair advantage for the utility and if corrective action is not taken will result in the demise of customers' competitive alternatives.

Over time, the primary benefits from electric industry restructuring will come, not from commodity cost savings, but from changes at the customer's premises. The provision of these value added services is key to establishing sustainable business relationships with customers. Moreover, the types of services customers want and are willing to pay for are highly competitive, not monopoly services.

For example, from a wide array of competitive options customers want to select those options whose value equals or exceeds their cost. If the utilities package of services do not meet the customers needs yet the costs remain bundled the customer must pay twice, once to the utility for valueless services and once to the energy service provider for the customized package of customer-selected services.

A simple example illustrates this point. Customer "Big" has many facilities located throughout the State. Historically this customer was served by 3 different utilities all of whom billed for each meter served. Each utilities' billing format and rate characteristics were different. Customer "Big" employed a small staff to aggregate the utility charges by business unit and review them for accuracy. As part of his new bundle of energy services Customer "Big" wants an aggregated electricity bill, including both utility and energy service charges, subtotaled by business unit and provided on-line through the internet. Why should this customer have to pay for the utilities to continue to send him useless information?

Q6 What services and costs should be unbundled?

A6 My recommendations are based on the cost and service format applied to California utilities and I recommend the Pennsylvania Commission evaluate these recommendations in the context of Pennsylvania's facts.

The cost elements that represent a minimum level of unbundling are:

1. Meters and meter reading
2. Billing and collections (including data processing costs)
3. Customer Service

4. Commodity Procurement, scheduling, balancing, risk management and sales.
5. Uncollectible Expense
6. Working Cash Allowance

Q7 What did the California Public Utilities Commission decide with respect to unbundling distribution services?

A7 In D. 97-05-037 the California Public Utilities Commission ordered the following:

Billing

1. Customers may choose from three billing options as follows: utility and the new Energy Service Provider (ESP) provide separate bills, the utility consolidates bills for itself and the ESP, or the ESP consolidates bills for itself and the utility.

2. ESPs who provide consolidated billing for the utility are responsible for payment of the billed amounts to the utility regardless of their ability to collect from their customers.

3. Utilities may impose reasonable creditworthiness requirements on ESPs who provide consolidated billing. These requirements are to be the same as those required of a similarly sized and situated customer.

4. ESPs who provide consolidated billing must describe the utilities' charges on their bills in a manner consistent with the bill reporting standards the CPUC sets for the utilities.

Meters and Meter Reading

1. Utilities who wish to employ Automated Meter Reading (AMR) (or any other type of advanced metering system) technology throughout their service territories may do so subject to the following conditions:

- utility customers will have the choice of deciding whether they want to use the real-time metering capability offered by the technology

- only customers electing to use the real-time pricing capability of AMR will be required to pay for the costs of that technology

- utility shareholders will be at risk for the full recovery of the technology's costs

- at the same time, the utility installing AMR would not be required to lower its revenue requirement associated with metering as a results of cost savings achieved from adopting the technology

- balances risk and reward between ratepayers and shareholders

- a utility deciding to adopt AMR would provide the Commission with a deployment plan showing how the technology would be geographically deployed and on what timetable.

2. ESPs may install their own meters and must agree to share the metered information with the utility. The ESP and the utility will enter into a service agreement specifying the nature of the information to be collected, the means for sharing data, and a reasonable approach for ensuring that the

metering equipment is installed, calibrated and maintained properly. The Commission will establish minimum standards governing open architecture for meters and communication.

- large customers may use ESP meters beginning 1-1-98
- ~~small customers (less than 20 kilowatts) may use ESP meters~~ beginning 1-1-99.

The Commission delayed installation of ESP meters for small customers by one year to "encourage a more studied movement through the various steps that must precede such a new commercial offering." (D. 97-05-039, pg. 17.)

Cost Separation

The Commission concluded that customers should not pay for costs that are not incurred and directed that utilities separately identify the net cost savings resulting from a customer's election to receive certain revenue cycle services from another service provider and to reduce distribution charges where appropriate.

Other Services

In addition to billing, metering and meter reading, the Commission found there are other costs related to customer service inquiries and uncollectibles that are "logically related to revenue cycle services." (D. 9705-039, pg. 18.) The Commission directed the utilities to identify the net customer service inquiry

savings to be used to reduce customer charges in those situations where an energy supplier chooses to handle customer service inquiries. In response to the concerns expressed by one party, the Commission directed all parties to evaluate whether a universal uncollectibles pool should be established to motivate ESPs to serve customers who pose a higher credit risk.

Q8 The issue of distribution service unbundling was hotly contested in California. Why do you think the California Public Utilities Commission ordered unbundling?

A8 In the California Commission's decision on unbundling (D. 97-05-039) Commissioner Jesse J. Knight, Jr. wrote as follows:

"Unbundling bottleneck facilities has played a key component in regulation of the telecommunications industry and was an important part of the Commission's efforts to ensure that full and fair markets properly develop. Access to bottleneck facilities and the unbundling of potentially competitive services allows greater innovation in services, a more customer focused marketplace and an important check on the ability of the dominant provider to leverage market power into adjacent markets. This decision takes this important lesson and applies it to the revenue cycle services of the electric industry."

Based on my active involvement in this proceeding and knowledge of the natural gas market in California I believe the Commission recognized that without revenue cycle service unbundling the competitive market in California would not flourish.

In 1991 when the California Commission opened the natural gas market to competitive choice they failed to unbundle services for residential and commercial customers (so-called Core Customers). As a result, the core natural

gas aggregation program never achieved significant market penetration and over the years participation of marketers has declined from a high of 12 to 3 or 4 remaining today. Once the margins on natural gas purchases from marketers fell to +/-5%, the marketers' profit margins fell to unacceptably low levels.

Although natural gas marketers and aggregators were allowed to furnish the customer a consolidated bill, the customer received no credit for this cost from the utility. Moreover, the utility maintained control of the meter and the natural gas ESP had to delay his billing until he received the data from the utility. Utilities refused to provide the data to the customer in computer readable form and the ESP had to re-data enter the information to produce customers' bills. All of these hurdles resulted in additional costs for providing the services with no offsetting credits.

Q9 Does this conclude your testimony?

A9 Yes.

NANCY I. DAY

CAREER SUMMARY

Senior executive with extensive experience managing large line and staff organizations through profound business, regulatory and market changes. Managed regional utility operations and facilities with a focus on improving cost effectiveness and customer service. Led regulatory initiatives during a period of deregulation. Built coalitions and successfully developed consensus solutions to business and regulatory issues. Results-oriented, team-based leader with expertise in the following:

Regulatory Affairs	Governmental Affairs	Administrative Law
Facilities Management	Customer Service	Materials Management
Purchasing	Risk Management	Labor/Management Relations

ACCOMPLISHMENTS

New Energy Ventures, Inc., Pasadena, CA — 1995-Present

The nation's first Energy Agent, representing buyers in competitive electricity and natural gas markets.

Vice President -Customer Services (1995-Present)

Develop competitively bid portfolios of electricity and natural gas for NEV clients, direct the provision of an array of customer services including portfolio management, billing, management reports, regulatory analysis and advocacy.

Southern California Gas Company, Los Angeles, CA — 1968-1995

The nation's largest natural gas distribution company serving almost 5 million customers. Annual revenues of $3 billion.

Vice President, Regulatory Affairs (1990-1995)

Senior officer responsible for developing and executing regulatory strategies, directing regulatory proceedings and maintaining effective agency contacts and relationships. Managed the staff of 30 professionals responsible for obtaining required regulatory authorizations from the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the Federal Energy Regulatory Commission. Testified before the California Legislature and presented oral arguments before the CPUC and the CEC.

- Led the regulatory initiatives that resulted in the landmark CPUC cost allocation decision to eliminate decades of cross-subsidies between customer classes.
- Directed the company's response to a CPUC-ordered management audit. This comprehensive audit examined every aspect of company operations over a 5-year period and resulted in no adverse findings.
- Implemented aggressive settlement strategies that successfully reduced litigation costs, regulatory delays and obtained the desired business results.
- Reduced the department's operating budget by 35% over 4 years.

Division Manager (1988-1990)
Senior operations manager responsible for the provision of natural gas and related services to 570,000 customers in the South Coastal Division. Managed over 700 employees and $60+ million budget related to the following: installation and maintenance of distribution pipelines and associated metering facilities, meter reading, telephone call center, bill reconciliation, collection, in-home appliance maintenance and repair, and public/government affairs.

- Refocused employee attention away from internal company processes to delivery of customer satisfaction. Customer complaints reduced by 38%.
- Dramatically improved labor/management relations and employee morale. Reduced grievances by 60% and improved employee safety by 22%.
- Instituted the first 12-hour telephone call center operation to improve customer service.
- Merged two divisions into one and consolidated the operation in a new headquarters.
- Revamped market research to obtain better information from our customers regarding customer satisfaction.

Manager of Material Services (1986-1988)
Managed the provision of centralized contracting ($150 million), purchasing ($120 million), warehousing, material distribution and inventory control services. Established functional policy for decentralized purchasing, contracting, and material management. Also managed the specialized fabrication and repair shops and the investment recovery operation.

- Lowered material delivery costs by 12%.
- Transformed a salvage sales operation into a profitable investment recovery operation and recycling program. Generated $1.5 million additional revenue per year.
- Redesigned the material distribution system to eliminate 60 local storerooms.

Manager of Risk Management and Claims (1985-1986)
Managed the placement of insurance, covering all aspects of the company's operations and assets, and the negotiation, settlement and litigation of claims against the company for property damage and personal injury.

- Completed the first comprehensive review of company loss control programs and recommended the strategy for increasing employee and public safety while reducing costs by as much as 30%.
- Instituted an aggressive contact program to achieve timely and low cost resolution of claims against the company.

Manager of Headquarters Services (1983-1985)
Managed the operation and maintenance of over 1 million square feet of office space in 5 different locations. Responsibilities included the following building occupant services: communications, reprographics, janitorial, mail and messenger, automotive maintenance, craft shops, archives, cafeterias, and travel.

- Created an in-house travel agency to earn commissions on all travel services. Offset costs by $100,000.
- Instituted a second shift in the reprographics operations to improve cost efficiency. Productivity increased by 26%.
- Instituted a cost planning and control system.

EDUCATION & PROFESSIONAL ACTIVITIES

Harvard University, Graduate School of Business Administration -
Advanced Management Program
University of Redlands - B.S. Business Administration
University of Southern California - Certificate of Management Effectiveness
Chairperson, Southern California Regional Purchasing Council

CERTIFICATE OF SERVICE

I hereby certify that on January 8, 1998, I caused a true and correct copy of the First Joint Stipulation executed by NEV East, L.L.C. to be served by federal express on:

John S. Moot, Esquire
Kurt Bilas, Esquire
1440 New York Avenue NW
Washington, DC 20005

and by first class mail on the following:

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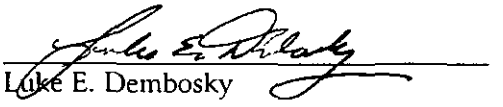

Luke E. Dembosky

REDACTED -- PUBLIC DISCLOSURE VERSION

Volume I

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Duquesne Light Company	))	Docket No. R-00974104

PREPARED DIRECT TESTIMONY OF DR. ROBERT B. WEISENMILLER

SPONSORED BY
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November 7, 1997

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Duquesne Light Company	))	**Docket No. R-00974104**

PREPARED DIRECT TESTIMONY OF DR. ROBERT B. WEISENMILLER

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

A. I am Dr. Robert B. Weisenmiller, Principal with the consulting firm of MRW and Associates, Inc., 1999 Harrison Street, Suite 1440, Oakland, California 94612.

Q. Please summarize your pertinent professional and educational experience.

A. I have a Bachelor of Science from Providence College and a Ph.D. in Chemistry and a Master of Science in Energy and Resources from the University of California at Berkeley. During 1977-82, I was employed by the California Energy Commission ("CEC") where the last position I held was Director of the Commission's Office of Policy and Program Evaluation. Since leaving public service, I have been an energy consultant. As part of my consulting practice, I have testified extensively before state and federal agencies, on issues that include utility resource planning, marginal costs, rate design and energy markets and energy regulation. Additional detail is provided in Appendix A hereto.

Q. On whose behalf are you appearing?

A. My testimony is jointly sponsored by several organizations. Hospital Shared Services ("HSS") is a non-profit organization which offers group purchasing services to voluntary, non-profit acute care hospitals. The areas HSS focuses on include: cost reduction opportunities, improved management effectiveness, income opportunities, and quality improvement. Administrative Resources Inc. ("ARI") provides similar services to nursing homes, retirement communities, closed pharmacies, physician group practices, clinics, surgery centers and managed care organizations. The following entities support the intervention of HSS and ARI:

Hospital Shared Services

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Forbes Metropolitan Hospital
Forbes Nursing Center
Forbes Regional Hospital
Ohio Valley General Hospital
South Hills Health System

Administrative Resources, Inc.

LGAR Health and Rehab Center
Vincention Home

I. INTRODUCTION AND SUMMARY

Q. Please summarize your analysis of Duquesne Light Company's ("Duquesne") stranded cost claims and rate proposals in this case.

A. Duquesne has not demonstrated that it has any stranded costs now, nor has Duquesne demonstrated that it will have any stranded costs as of January 1, 2006. In fact, by Duquesne's own belated admission, as of January 1, 2006, its estimated stranded costs may be a negative $233 million -- thus Duquesne admits that, as of January 1, 2006, the market value of its generation-related assets may exceed the remaining net book by $233 million. That admission is critical because it shows that Duquesne fails the test that Duquesne itself stated it had to satisfy to be entitled to its rate proposal in this case. Duquesne proposed to accelerate depreciation and amortization of Duquesne's generation and regulatory assets by $1.7 billion through 2005 and to continue to charge Duquesne's current rates, adjusted for an energy cost rate ("ECR") of 14.7mills/Kwh. Because Duquesne failed its own test, its request to accelerate depreciation and amortization should be denied; Duquesne's rates should be reduced to a level that is cost-justified without reliance upon accelerated depreciation and amortization; and, Duquesne should be denied any recovery of stranded costs it may claim to have.

Q. Will you provide a brief summary of Duquesne's stranded cost claim and its rate proposal?

A. Duquesne does not claim to be able to quantify with any degree of accuracy, or in fact know what will be, its stranded costs as of January 1, 1999. Further, Duquesne contends that it is not possible to predict long-term future market prices for electricity with any degree of confidence. For instance, Duquesne's President and Chief Executive Officer, David Marshall, testifies that "the uncertainty inherent in such projections poses significant risks for both investors and consumers and cannot be consistent with the known and measurable standard." Marshall, Duquesne Statement No. 1, at 14:12-14. Therefore, Duquesne's position is that there needs to be a real market valuation to establish stranded costs.

Notwithstanding that rhetoric, Duquesne's stranded cost claim in this case and its rate proposal rest exclusively on the very type of predictions of long-term future electric prices that Duquesne criticizes. When Duquesne filed its application on August 1, 1997, Duquesne proposed to accelerate depreciation and amortization of its generation and regulatory assets by $1.7 billion through 2005, but it claimed that even with that accelerated depreciation and amortization, as of December 31, 2005, it still would have $8 million to $582 million in remaining stranded costs. That $8 million to $582 million stranded cost claim was derived from a comparison of Duquesne's projected net book value of generation-related assets at the end of 2005 based upon a projection of the costs of operating those assets versus the net present value of the revenues it projected it would earn based upon a projection of market prices through up to 2026. Marshall, Duquesne Statement No. 1, at 13:14-18. The

predictions of long-term future market prices were provided by Duquesne's witness Michael Schnitzer. The predictions of the long-term costs of operating these generating assets are set forth in Duquesne Witness Clayton's exhibits.

The fact that Duquesne is relying on the very type of methodology that it criticizes as flawed should serve as a basis alone to reject Duquesne's claims and proposals in this case. However, it is important to clearly and concisely summarize the ramifications *vis-a-vis* Duquesne's rate proposal that flow from Duquesne's reliance on a prediction of long-term future electric generation prices to establish a range of stranded cost estimates.

An integral part of Duquesne's proposal to accelerate amortization and depreciation by $1.7 billion is its request to be granted authority to continue to charge its current rates. As support for that request, Duquesne claims that the accelerated amortization and depreciation will be used to mitigate stranded costs. However, that claim begs the question: does Duquesne, in fact, have any stranded costs to mitigate? If it has no stranded costs, the accelerated depreciation and amortization simply provides Duquesne a way to provide artificial support for rates that would not otherwise be cost-justified. That in turn means that Duquesne's current rates are, or would be, over recovering Duquesne's costs. Therefore, a critical question is: has Duquesne made the *prima facie* showing that it said it had to make to justify its request for authorization to continue to charge its current rates? To make that showing,

Duquesne said it had to demonstrate two things: (1) that "excess earnings" under its current rates would be used to mitigate stranded costs, and (2) that notwithstanding that mitigation, Duquesne still would have stranded costs remaining in 2006.

As I noted before, Duquesne purported to make the latter showing by relying on Mr. Schnitzer's prediction of future market prices and Duquesne's calculation that as of January 1, 2006, it would have $8 million to $582 million in remaining stranded costs. However, in its August 1, 1997 application, Duquesne overstated its projection of embedded costs. As a consequence, it later acknowledged in response to several interrogatories that it needed to change its stranded cost estimate. Exhibit RBW-1. (Duquesne Supplemental Response to HSS-1-001, *et al.*). It admitted that instead of having a minimum of $8 million in stranded costs remaining in 2006, its generation-related assets might instead have a positive market value of $233 million. Thus, Duquesne does not meet its own standard for continued collection of its current rates.

Q. Did you undertake any independent analysis to determine whether Duquesne has any stranded costs?

A. Yes. I examined a real market transaction to determine the market value of Duquesne's generation assets. I examined the value that Duquesne's future merger partner, Allegheny Power Systems ("APS"), sees in the market as reflected by its purchase of Duquesne's interest in the Ft. Martin plant, as well as market valuations

made by Duquesne and Duquesne's financial advisors in internal documents. Based on the price a willing buyer paid a willing seller for the Ft. Martin unit, which is free to sell power at unregulated prices, I determined that the market value of electric generation is greater than the value of Duquesne's net book generation assets. Consequently, Duquesne has no stranded costs, or any right to collect amounts attributable to stranded costs. Thus, its request to accelerate depreciation and amortization -- which benefits only Duquesne by inappropriately propping up its cost structure -- should be denied, and Duquesne should be required to reduce its rates.

Q. What advice, provided to Duquesne by its financial advisors and referenced in your last answer, do you have in mind?

A. In stark contrast to its claims here, as recently as November 1996, Duquesne received detailed analyses from various financial advisors that the market value of its generation assets could exceed net book value by up to $734 million. Many *previously non-public financial planning and valuation documents provided by* Duquesne in discovery reveal a financial picture that is strikingly different from the picture that Duquesne paints here, as described below.

Q. With that preface, will you now describe the structure of your testimony?

A. Section II of my testimony discusses the policy challenges the Commission faces in analyzing Duquesne's request to recover claimed stranded costs.

Section III contrasts Duquesne's claims here with the fact that both Duquesne itself and the financial community repeatedly concluded that the value of Duquesne's generation assets exceed Duquesne's net book costs. That section also shows that the studies understated the value of Duquesne's generation assets when Duquesne's sale of its interest in Ft. Martin is considered. Section III also contains a discussion that shows that the results of Duquesne's June, 1997 Request for Proposal ("RFP") do not establish a valid measure of the retail market value of electric power in Duquesne's service territory.

Section IV shows that Duquesne failed to make a *prima facie* showing that it is entitled to continue to charge its current rates. Section IV also shows that Duquesne's capital additions since its last base rate case in 1986 may not be just and reasonable. Section IV further shows that Duquesne's projections of capital additions and O&M expenses are inflated.

Section V shows that Duquesne has failed to undertake a number of measures to substantially mitigate whatever stranded costs it might have.

Section VI shows that Duquesne exaggerated its claimed amounts of regulatory assets and transition costs to the tune of hundreds of millions of dollars.

Section VII shows that Duquesne inflated its claimed stranded costs by utilizing unreasonable approaches and assumptions to reduce predictions of future market prices to artificially low levels.

Section VIII demonstrates that Duquesne's ostensible consumer protection features, such as the proposed mechanisms to trigger an early end to Duquesne's accelerated depreciation and collection of competitive transition charges ("CTC"), provide no protection whatever and could detrimentally impact ratepayers.

Section IX discusses alternatives Duquesne could use if it believes that it has stranded cost exposure; namely, sale of its generation assets in the open market to establish a known and measurable level of stranded costs. If notwithstanding Duquesne's criticism of computer-generated predictions of long-term future market prices, it is permitted to recover stranded costs based upon those price predictions, the risks associated with Duquesne's price predictions and the assumptions on which they are based should be placed on Duquesne, not its customers. If Duquesne is allowed to recover computer-predicted stranded costs, it also would be required

(i) throughout the forecast period to offer its power output at the market-clearing price established by Mr. Schnitzer's price predictions to those customers who already have paid Duquesne stranded costs; and

(ii) for stranded cost over-collections to compensate customers at a 14.78% interest rate reflecting Duquesne's average anticipated return on common equity for 1997-2001.

Further, because Duquesne failed to satisfy its own test for authorization to continue to charge its current rates, Duquesne should be directed to reduce its current rates.

Section X compares Duquesne's projected prices to power market expectations from a variety of sources and concludes that Duquesne's projections are particularly unrealistic.

II. DUQUESNE'S INCONSISTENT STATEMENTS PRESENT SIGNIFICANT POLICY CHALLENGES

Q. What are the chief policy challenges the Commission faces in these restructuring proceedings?

A. There are at least three:

1. How to induce utilities to realistically estimate stranded costs;
2. How to induce utilities to reduce stranded costs going forward and convey those benefits to ratepayers; and
3. How to promote competition in the future so that consumers will indeed reap the benefits that are supposed to result from their payment of stranded costs.

Q. Addressing the first policy challenge you identified, can you state whether Duquesne has an incentive to inflate stranded cost claims?

A. Yes, it does. This proceeding is an excellent example of that incentive at work. The greater Duquesne's stranded costs, the greater the amount of money Duquesne can

recover on a non-bypassable, non-competitive basis from ratepayers. Further, inflation of the stranded cost claims benefits Duquesne's shareholders by:

1. Accelerating the return of, and receipt of return on, shareholder investment;
2. Delaying the day when effective competition benefits Duquesne's customers;
3. Reducing the Company's future cost of generating electricity, thereby increasing the Company's competitiveness relative to alternate suppliers that might want to enter the market and/or increasing the amount that shareholders will earn when competition, not regulated rates based on that Company's historic cost levels, establishes the price of generated electricity in the restructured industry.

Q. Is it important to incent utilities to realistically estimate stranded costs?

A. Yes. Excessive stranded cost claims will delay the availability of benefits envisioned to flow from competition. So long as utilities' customers pay stranded costs in addition to the price of electricity as a stand-alone commodity, their potential costs savings are marginal, at best. As a consequence, effective competition will not start until stranded cost recovery is completed. Delay in the date of effective competition has broad negative consequences, such as impeding job growth in the Commonwealth because businesses forced to bear stranded costs over longer periods will have less to invest and less to spend on payroll.

Further, over-compensating the utility will reduce the utility's cost of generating electricity below the market clearing level after the transition period is over. In turn that will disadvantage other, non-subsidized power merchants in the new market environment, to the benefit of utility shareholders.

Q. Won't ratepayers benefit if Duquesne reduces its cost of generating a kilowatt of electricity below market clearing levels during or after the end of the transition period?

A. Not necessarily. In the new generation market, the market sets the price of generated electricity, rather than a regulator designing rates based upon the particular costs experienced by a single utility. When the market sets the price, the company with a cost of generating electricity below the market price retains the difference to benefit its shareholders. Customers do not see a commensurate benefit.

Q. Why is the second policy challenge, namely to induce stranded cost mitigation to the maximum possible extent, important?

A. The utility has the ability to mitigate stranded costs going forward. If ratepayers are being asked to pick up the tab, they are entitled to a mechanism that promotes the most aggressive cost containment steps possible.

Q. Why is the third policy challenge, namely promoting effective competition in the future, important?

A. The theoretical justification for the deregulation of electric generation rates is that vigorous competition is the most effective means of reducing prices. However, for the market to discipline electric prices, there must be effective competition.

Q. Do you think that approval of Duquesne's application, as filed, will promote competition?

A. No. I believe that Duquesne's proposal will thwart competition and impede the very purpose of the Act, *i.e.*, to provide customer choice.

As I just described, when Duquesne reduces its future cost structure by maximizing near-term stranded cost recoveries, it can, in effect, place itself in a *supra*-competitive position when real competition begins in the post-transition period. As a consequence, it will be difficult for new suppliers to enter the market and meaningfully compete with Duquesne for market share. That is precisely the result that will occur under Duquesne's proposal. If Duquesne's proposal is accepted, Duquesne will accelerate recovery of $1.7 billion, reduce the total cost of power supplies it owns or controls below market-clearing prices, and retain ownership of such assets (having artificially low costs) when the generation market is supposed to be opened to competition. Those consequences would result from one significant factor, *i.e.*, that Duquesne would obtain recovery of $1.7 billion that Duquesne has not justified. Therefore, approval of Duquesne's application, as filed, will result in

Duquesne's recovery of costs to which Duquesne is not entitled and will delay substantially the day when Duquesne's customers benefit from competition.

III. DUQUESNE HAS NO STRANDED COSTS

Q. What is Duquesne's estimate of the stranded costs it will experience as of January 1, 1998?

A. As I previously indicated, Duquesne has not provided one. In fact, according to Duquesne, the "Company has not quantified a present value of stranded costs as of January 1, 1998." Exhibit RBW-2. Instead, Duquesne Witness Clayton would prefer that any calculation of stranded costs be delayed until mid-2003. Clayton, Duquesne Statement 2, p. 28:16-20.

Q. Does Duquesne estimate stranded costs at all?

A. Duquesne's originally filed case claimed that as of January 1, 2006, it would still have stranded costs ranging from $8 million to $582 million. However, on October 16, 1997, Duquesne notified participants that correcting for a series of errors in the calculations incorporated into the originally filed case, Duquesne might not have stranded costs at all on January 1, 2006, but instead might enjoy a positive benefit of as much as $233 million. *See* Exhibit RBW-1 (8 page supplement).

Nonetheless, Duquesne claims that it will not be able to recover in a competitive market costs of between $1.549 billion and $2.205 billion, reflecting the adjustments contained in its October 16, 1997 notice.

A. Duquesne's Claim For Stranded Costs Is Refuted By Its Own And Its Financial Advisors' Assessments Of The Value of Duquesne's Generation Plants

Q. Is that claim consistent with Duquesne internal studies, presentations to Duquesne by investment bankers, and reports by Duquesne's consultants?

A. No. Documents that constitute those studies, presentations and reports were produced by Duquesne to HSS/ARI in discovery. Those materials show that Duquesne's generation facilities could be worth hundreds of millions of dollars more than the Duquesne is willing to admit when it demands stranded cost recovery from its ratepayers.

Q. How does Duquesne assess the value of its generation assets for purposes other than claiming stranded costs from its customers?

A. Duquesne reviewed various scenarios involving the possible sale of its generating assets in a 70 page study. Duquesne concluded that the"[s]ale of generating assets can add between $500-$750 million in after tax cash for investing," and that "deferring tax [consequences] could double those amounts." Particularly, according to Duquesne the"[s]ale of [the] Cheswick and Elrama [units] shows strong economics." Exhibit RBW-3, at 12.

Q. Can you detail some of the study's specific results?

A. Yes. The study concluded that selling just the Cheswick and Elrama units would yield "purchase premiums" of $160 million in a base case scenario, $335 million if power sales were to be increased, and $460 million if sales increased and O&M costs were reduced by one-third. Earnings per share in Duquesne's study would increase by nearly 50% annually by 2003 compared to a business-as-usual approach. Exhibit RBW-3, at 8.

Q. Did the Company assess the value of all of its fossil generation assets under these scenarios?

A. Yes. It calculated that it might capture a "purchase premium" of more than $730 million in addition to net book value on the plants. Exhibit RBW-3, at 10.

Q. Please describe how Duquesne determined the "purchase premiums."

A. Duquesne presumed a number of circumstances. First, the Company projected that property tax, income tax and interest rates would remain static. Duquesne assumed that it would purchase the plants' output for ten years (starting in 1995, the year of the study) at prices that covered the revenue requirements of the plants. Of course, under Duquesne's proposal in this case, the plants' revenue requirements are more than covered. The calculations presumed a static cost of capital at 8.55% for the plants, compared to Duquesne's current overall cost of capital of 10.94%. The study further presumed post-2005 sales at $.04/Kwh.

Q. What presumptions were incorporated into the increased sales scenario?

A. Duquesne presumed that additional output would be sold at $.025/Kwh for the first ten years of the projection, and at $.04/Kwh thereafter. In fact, Duquesne Witness Schnitzer estimated the ceiling price in the year 2006 in the range of $34-$44/MWh, or 3.4 to 4.4¢/Kwh. *See* Statement No. 3 (Schnitzer) at p. 27:7-13. In Duquesne's study, the benefits of the increased revenues resulting from the increased sales were "used to increase [the] plant purchase price."

Q. What circumstances were changed for the reduced O&M scenario in Duquesne's valuation of its plants?

A. Labor costs were reduced by 33⅓% and the benefit was used to "increase [the] plant purchase price." (In fact, Duquesne's own consultants indicated that simply bringing the Company's performance up to the industry's "best practices [would] reduce total personnel by 45%." Exhibit RBW-4 (typeface changed from original)).

Q. Have Duquesne's consultants conducted valuation studies of Duquesne's generation assets?

A. Yes. They too have calculated that Duquesne's generating assets may be worth hundreds of millions of dollars *in excess* of net book value.

Q. Please describe the calculations of Duquesne's consultants.

A. Duquesne consultants Metzler & Associates performed an asset valuation using, among other things, Duquesne's "fuel price projections." Three scenarios for power prices were outlined:

- a "Worst Case" with prices at $18-20/MWh (which is at or above the price Duquesne claims in its filing with the Commission is the current market clearing price, see Statement 3, p. 27:7-13);
- a "Most Likely Case" starting at $27/MWh, rising to $35/MWh in 2005 (consistent with Duquesne's own resource plan); and
- a "Best Case" starting at $35/MWh using a levelized forecast.

Exhibit RBW-5, at 2.

Under the foregoing scenarios, Cheswick's value ranged as high as $225 million, and Elrama's, as high as $150 million. The study was dated July 15, 1996. Exhibit RBW-6.

Q. Did Metzler & Associates subsequently perform additional valuations of the Duquesne generating assets?

A. Yes. In an August 1996 study, Metzler again conducted a valuation study. According to that study, based upon "comparable valuations," the value of Cheswick could reach $264 million (book value: $120 million); Elrama $224 million (book value: $100 million); Brunot Island $112 million (book value $26 million); and Phillips, $140 million. Exhibit RBW-7 at 3 and Statement No. 1, Testimony of Donald J. Clayton, Exh. DJC-3 at 32-38.

Q. Did Duquesne's consultants have general observations about the benefits of divestiture?

A. Yes. In the August 5, 1996 study, Metzler noted that a third party sale of generation assets presented the"[p]otential to receive [a] better price." Exhibit RBW-7, at 4. In August 1996, materials Metzler noted that divestiture presented a "[h]igher probability of achieving price[s] above book value." Exhibit RBW-8, at 4. Similarly, Metzler observed that the sale of Duquesne's generating assets in a separate "Genco" unit "provides the strategic investor with a much more robust market presence." *Id.* at 5. According to the report,"[p]roceeds of an asset sale can be used to offset nuclear stranded costs with or without a GENCO." *Id.* at 6.

Q. Is there a general trend that you can detect in the Metzler materials?

A. Yes. As the outlines of the Pennsylvania legislation became clearer, Duquesne's consultants attempted to hedge any potentially favorable valuation of the generation assets with disclaimers, presumably so that if Duquesne intended to claim enormous stranded costs, the consultants' reports could be marginalized or the positive valuation results dismissed.

Q. Is Duquesne's claim for fossil generating plants stranded costs in 2005 of over $152.4 of net present value consistent with even the pessimistic cast placed on valuation by its consultants?

A. No. The consultants suggested at one point that the "net value of all [fossil generating] assets is slightly below book value." Exhibit RBW-9, at 3. However, they also noted that Duquesne's fossil "generating [capacity] is a viable business with stranded cost mitigation," based on the belief that as an independent, non-regulated generating company, it "addresses remaining stranded costs with cost structure improvements."

Q. What was the maximum valuation of the Duquesne generation assets made by the Duquesne consultants?

A. The Metzler firm indicated that the value of just four of the generating facilities could *exceed* depreciated net book value by more than $657 million. Exhibit RBW-9, at 4.

Q. Are the investment bankers' evaluations of Duquesne's generation assets consistent with those of the consultants?

A. They show even higher market valuations.

Q. Please explain.

A. Less than a year ago, and after the Metzler studies described above, the investment banking firm CS First Boston presented Duquesne with a detailed 130 page study of five of Duquesne's generation units. The units were depicted with market values of

between $827 million and $1.184 billion, exceeding net book values by $377 million to $734 million.

The following table summarizes the CS First Boston results.

Table III-1-CS First Boston Valuation

Plant	Net Book (millions/$)	High Value (millions/$)	Low Value (millions/$)	Purchase Premium Over Book (millions/$)
Cheswick	119	368	266	147-249
Elrama	98	231	165	67-133
Sammis	53	101	74	21-48
Eastlake	43	114	84	41-71
Mansfield	137	370	238	101-233
Total	450	1184	827	377-734

Q. Can you describe projected net income streams from the plants contained in the study?

A. For the period 1997-2006, CS First Boston's study explored a scenario in which net income increases for the Cheswick plant by more than 270%, for Sammis by more than 170%, for Eastlake by more than 245%, for Mansfield by more than 1100%, and for Elrama by nearly 3000%. That projected revenue stream casts in an entirely new light Duquesne's claim here that 2006 would be the earliest that Duquesne could extinguish claimed stranded costs. Excerpts of the CS First Boston report to Duquesne are contained in my Exhibit RBW-10.

B. APS' Acquisition of Duquesne's Interest in Ft. Martin Establishes that Duquesne Has Inflated Its Claimed Stranded Costs

Q. Are there other measures of value that demonstrate that Duquesne's estimation of stranded costs is inflated?

A. Yes. Duquesne's sale of its interest in the Ft. Martin plant provides a real market valuation of generation assets that can serve Duquesne's service territory. The economics of that transaction are fully consistent with Duquesne's internal studies, reports of its consultants and advice from its financial advisors except that the price paid for Duquesne's share of the Ft. Martin plant was even greater than the gains projected on the sales of Duquesne's remaining assets by the sources described in Part III.A.

Q. Please describe the assets involved in the Fort Martin transaction.

A. Duquesne sold a 50% undivided interest in Unit No. 1 of the Fort Martin Power station to AYP Capital, Inc. ("AYP"), an unregulated subsidiary of Duquesne's future merger partner, Allegheny Power System, Inc. ("APS") for $169 million. That price was more than four times the net book value of $37 million. Ft. Martin is a steam electric generating unit located on the Monongahela River in Maidsville, West Virginia. Duquesne's share of Unit No. 1, which is operated by Monongahela Power Company, another subsidiary of APS, has a summer rating of 276 MW, so AYP paid over $612/kW. This transaction included the related fuel and materials and supplies

inventories, along with the associated Operating and Transmission Agreements. It closed after receipt of regulatory approval effective May 23, 1996.

Q. Is this transaction a good measure of the value of generating capacity in this region?

A. Yes, it should be, given that it was freely negotiated between two sophisticated parties. As the operator and part-owner of Fort Martin, APS obviously was very well positioned to fully judge the value of the facility. Given the magnitude of the transaction, APS must have been relatively comfortable with this investment.

Q. What was the basis for AYP investment in this facility?

A. West Penn provided a May 3, 1996 letter from New Harbor Incorporated (the broker of the deal for the buyer) and a projection of electric prices for the ECAR submarket that was performed by R. J. Rudden Associates, Inc. using the RJRA Electric Power Market Model. Those projections are presented in Table III-2.

Table III-2. Power Prices underlying AYP purchase of Fort Martin[1]

Year	1999	2000	2001	2002	2003	2004	2005
Price($/MWh)	34.5	37.3	40.2	43.4	49.3	50.5	54.4

[1]Assuming inflation of 2.2% for 1994 through 1997, and RJRA's 3% value thereafter.

Q. How do those price projections compare to the price projections that Duquesne relies upon to determine that it still will have remaining stranded costs in 2006?

A. Duquesne does not expressly purport to set forth comparable price projections. However, Mr. Schnitzer's Exhibit MMS-4 which serves as the basis for his and Duquesne's claimed market value in 2006, sets forth price projections based upon the results of Duquesne's RFP, as recalculated by Mr. Schnitzer. Schnitzer, Duquesne Statement No. 3, at 34:13-20. Those price projections are as follows:

Table III-3: Power Prices Calculated by Duquesne Witness Schnitzer

Year	1999	2000	2001	2002	2003	2004	2005
Price($/MWh)	18.7	19.7	20.8	21.9	23.1	24.3	25.6

Given that those are the implicit price projections Mr. Schnitzer used to establish market value as of 2006, it is not surprising that Duquesne has claimed remaining stranded costs as measured against those predicted prices. However, when Mr. Schnitzer's price projections are compared to the price projections that served as the basis for APS' purchase of Duquesne's interest in Ft. Martin, it is clear that Duquesne has substantially understated the projected market value of electric generation. Further, the fact that Mr. Schnitzer's calculations were based upon the results of Duquesne's RFP does not provide any greater degree of reliability to his price projections.

C. Duquesne's RFP Results Are Highly Misleading

Q. Before you explain why the results of the RFP are unreliable, will you explain how Duquesne relies on the RFP for its stranded cost claim?

A. Duquesne actually relies on the RFP results in two ways. First, as I just discussed, the RFP results serve as the basis for Mr. Schnitzer's 1999 to 2005 price prediction. Therefore, the RFP results form the basis for Duquesne's claim that it might have stranded costs in 2006.

Second, Duquesne proposes to use an annual solicitation to set each year's CTC until at least 2003. Presumably, Duquesne intends to conduct those solicitations in a manner similar if not identical, to the way in which it conducted the RFP. Therefore, if the RFP results in an artificially low price, that would have the two-fold effect of increasing Duquesne's stranded costs and setting a target price against which alternate suppliers could not realistically compete. As a result, it is important to understand why Duquesne's 1997 RFP results are a distorted measure of real market value for electric generation in Duquesne's service territory.

Q. Will you describe Duquesne's RFP?

A. According to Duquesne's testimony, Duquesne issued the RFP in June 1997. Duquesne offered to sell in a wholesale transaction a minimum of 50 MWs of firm power for a one-year period and a minimum of 100 MWs (with a maximum of 500 MW) of firm power for an eight-year period commencing on January 1, 1998. Duquesne stated that it received five bids for the one-year sale and eleven bids on the

eight-year sale. Contracts were executed with two entities for a total sale of 50 MWs for one year, and with one entity for a sale of 100 MWs for the eight year period. The weighted average price for the one-year sale was $18.16/MWh and the winning bid for the eight year sale was $20.19/MWh on a "nominal" levelized basis. The agreements for these power sales were executed during July and August 1997.

Q. Why does Duquesne's approach under-estimate the market clearing price?

A. My conclusion is based on the following: (i) because of its design, the RFP results reflect the value of incremental energy at a power plant within the Duquesne control area only, as opposed to the market clearing price within the region as a whole, and therefore do not adequately represent the impact of future supply/demand dynamics in the region, nor do they reflect power prices outside of its service territory, (ii) the terms and conditions of the solicitation were prescriptive and diminished value to potential buyers, (iii) bidders were provided no assurances that they would be able to purchase firm transmission rights on Duquesne's system or from Duquesne's system to their loads, (iv) the solicitation was for energy only (*i.e.*, prices bid did not reflect the cost of transmitting power or any necessary ancillary services), and (v) the contract had a take-or-pay provision at a relatively high capacity factor, which could have resulted in a fairly high delivered price in the absence of firm transmission rights. Each factor would work towards depressing bid prices, thereby understating the price for power.

Design Flaws

Q. How was the design of the RFP flawed?

A. First, I do not believe the prices resulting from a 50 MW annual auction are reflective of the value the market as a whole will place on energy in 1998 or in the years through 2005. The Duquesne RFP *at best* tested the market in 1997 for incremental quantities of firm power delivered within the Duquesne system, which was a fairly shallow market for *wholesale* power. For example, a solicitation for 50 MWs (or even 500 MWs) is for a small quantity of power relative to a solicitation for all the power needs of Duquesne, the Western Pennsylvania region, or the PJM and/or ECAR regions as a whole. (For example, 50 MW represents only 2% of peak demand in Duquesne's service territory, and 0.05% in ECAR). Generally, when economists draw supply/demand curves, they expect the price to increase as the purchased quantity is increased all else being equal.

At best, the RFP measures the *incremental* generating costs of incremental output from existing generation that has already been committed, similar to the system lambdas. These incremental costs do not include any "start-up,"or "no load,"variable O&M costs, much less any of the "to go" or "going forward" costs, such as fixed O&M costs, capital additions or fixed fuel costs. In Duquesne's terminology of these type of incremental costs do not include "to go" costs. Beyond these types of variable costs, the total costs of these assets include return on and of equity. In fact, Duquesne's President and CEO stated:

> If bid process accurately reflect sellers' costs, all suppliers would at least recover their out-of-pocket costs and most would receive some contribution to capital recovery. With many sellers, the resulting market clearing price provides for an efficient allocation of resources in that hour.

Q. Dr. Weisenmiller, please explain these various types or levels of generating costs?

A. Exhibit RBW-11 illustrates these concepts for the Duquesne system. Duquesne has testified that its unbundled *total* costs of generation are over 60 $/MWh, where the total costs include essentially sunk costs (*e.g.*, the return on and return of equity in the plant) and expected variable costs. Duquesne has also estimated its "*to go*" or "*going forward*" costs for these generating units, *see* Exhibit RBW-12, as between 23.3 $/MWh and 35.9 $/MWh on a 5 year levelized basis. "*Going forward*" costs are those costs that Duquesne will have to incur to continue operating the plants (*e.g.*, fuel, labor, more capital additions, etc.) Finally, the "*system lambda*" reflects the incremental costs to operate the marginal plant on the Duquesne system to produce a small quantity of additional power, which is typically the incremental fuel charge. For example, Duquesne's system lambda at 75% capacity factor was approximately $18/MWh in 1996. *See* Exh. RBW-13.

Q. Please explain the role of these various types of costs in competitive markets?

A. First, no one would commit to buy or build a power plant unless they believed the market for power was above their total generating costs. In terms of existing assets, even if a firm had totally written off all of its sunk costs (which Duquesne has not proposed), it would not typically sell unlimited quantities of a product for 22 $/MWh

(levelized over 5 years), whose costs to produce (*i.e.*, "to go") range between 23.3 and 35.9 $/MWh (on a similar levelized over 5 years basis). Generally, in a competitive market a firm only would commit to sales at prices at least covering its "to go" costs. The only way such an arrangement *not* covering "to go" costs might make economic sense is if someone was *already paying* over $60/MWh for large quantities of the product, so there can be a "fire sale" on the surplus products. Alternatively, a firm might find reasons to engage in some form of "predatory pricing" to achieve a strategic advantage relative to its competition.

Q. What would be the long-term impact of an 18 $/MWh market clearing price?

A. There are not many power plants with "to go" costs as low as 18 $/MWh, so that even after writing off all their sunk costs, the owners of these assets would have to decide how long to operate at a loss. Plants with higher operating costs would be shut-down, which would reduce excess capacity and drive the market towards equilibrium. As supply contracts, the market price will increase to a level high enough too attract either operation of the shut-in units or construction of new capacity which will seek to cover not only incremental costs, but also fixed O&M and capital investments. This will effectively push up market prices.

Q. When would sales occur at incremental costs or the system lambda values?

A. In competitive and economically rational markets, most firms typically do not sell unlimited quantities of a product for 18 $/MWh that cost them significantly more to

produce on a "going forward" basis. Instead, firms would make incremental sales at prices close to their incremental costs, when such sales did not undermine their longer-term and more profitable sales opportunities.

Limited Terms and Conditions

Q. How would a strategic bidder view an annual auction of 50 MW?

A. Power marketers hedge their contracts by developing similar procurement and supply obligations. Bidders would only be interested in the auction if they required either one year or eight years of power starting in 1998. Under Duquesne's inflexible terms, they could not bid for say 5 years of power starting in 2002. Given the take-or-pay commitment, bidders were limited to parties requiring more or less baseload power. Similarly, the limitation of bidding for a constant power level in the longer-term RFP would have little attractiveness to any party that expected to have increasing (or decreasing) needs for power over time. Finally, power delivery was limited to the Duquesne busbar. All of these limitations would tend to either reduce the number of potential buyers and/or reduce the price bid by potential buyers.

Moreover, in competitive markets, merchants do not set terms and conditions on a "take it or leave it" basis. Instead, merchants take pains to maximize flexibility of service or to customize service to capture premiums or gain a competitive edge over competitors. But Duquesne's RFP process was at the other end of the customer service/competition spectrum, with the predictable result of diminished value. In a

competitive market, sellers try to experiment and change to fit the needs of the buyer, rather than vice versa. As I discussed above, sales in the market not encumbered with inflexible terms reducing buyers' options and value, reveal prices that are much higher than received for Duquesne's dump wholesale -- for instance, consider the Fort Martin capacity sale.

Q. Do you have evidence that supports your assertion that Duquesne's proposed terms were inflexible and that the inflexibility affected the bidding process?

A. Yes. Duquesne responded to frequently asked questions in the course of conducting its RFP. One question was: "Would bids which deviate from the bid floor price, length of purchase, or other terms and conditions specified in the RFP be considered?" Duquesne's answer to that question was: "No . . . ." Exh. RBW-14. Moreover, to the extent a bid varied from Duquesne's set terms and conditions, Duquesne did not accept the bid, regardless of its terms. For instance, one term of a bid was that facsimiles would not be accepted. Based on that term, Duquesne rejected a bid that was hand-delivered and otherwise received on a timely basis, but was a facsimile. *Id.* That bid for the one-year term was $20.00/MWh or $1.84/MWh higher than the weighted average of the two bids Duquesne accepted. Exh. RBW-15 (60235). Further, the bid submitted by that party for the eight-year sales arrangement was higher on a net present value basis that the bid Duquesne accepted regarding the longer-term sales arrangement. As a result, it is evident that Duquesne's inflexibility

extended to terms that were designed to discourage bids, particularly those that might have set forth a price that was higher than fit Duquesne's design.

Transmission Limitations

Q. Could you please explain your third concern?

A. Yes. Page two of the solicitation flatly warned potential bidders that Duquesne "is not responsible for procuring the necessary transmission and ancillary services on Duquesne's transmission system to resell the power . . . ." (Statement No. 7, Exh. RAI-4, page 2 of 54.) In his testimony, Duquesne Witness Irvin reiterates this point (Statement No. 7, page 11): "Under the RFP, purchasers were required to secure transmission service over the Duquesne transmission system. Therefore, the bid prices that Duquesne solicited relate solely to the value of Duquesne's firm power at the generating station, not the cost of delivering that power (*e.g.*, transmission charges)."

Under the terms and conditions of the RFP, the bidder is essentially taking service at the Duquesne busbar. Therefore, the price does not reflect the cost of transmission access and required ancillary services such as losses and scheduling. As a result, the bidder would need to purchase transmission under Duquesne's open access tariff, including ancillary services, as well as any transmission access in place in the control areas into/through which this power is being delivered. For example, if a Buyer were to bid 19 $/MWh for power in 1999, but then had to pay an effective

transmission rate of at least 2.2 $/MWh (with a 100% load factor, as proposed in Schedule 7 of Duquesne's Open Access Compliance Tariff Filing plus an ancillary service charge for losses (which Section 15.7 indicates is .9%), the effective value of the power at the Duquesne border would be in excess of 21.1 $/MWh.

Q. Regardless of the value of power at the point of delivery, doesn't the RFP determine the market clearing price within Duquesne's service territory?

A. No. The RFPs were for wholesale, not retail, transactions. Power at Duquesne's busbar is only valuable to independent merchants within the Duquesne service territory after restructuring has occurred and a competitive market exists for Duquesne's current retail customers. Anyone who bid in these RFPs to buy power from Duquesne for these retail markets would be incurring the "take or pay" charges for firm power without any assurance that the retail market could be contested (given Duquesne's high stranded cost claims).

Transmission From The Duquesne Border

Q. Given FERC's Order 888 and other restructuring initiatives, would transmission access still be a concern to anyone responding to the Duquesne RFP?

A. At one time GPU felt that it had to build a transmission line to move power on a firm basis from Duquesne to its service territory. FERC Order 888 has generally established the requirement that transmission access be provided on a "comparable service" basis. However, the precise availability, terms and conditions of such

transmission access still is uncertain. For example, the precise availability, terms and conditions for transmission access, as well as its availability, throughout the PJM and ECAR, Independent System Operator ("ISO") are still very unsettled.

Indeed, an ECAR-wide or PJM-wide ISO is far from being implemented. Several of the utilities in ECAR object to joining an ECAR-wide ISO. This reluctance has worked to depress the value of any power sold pursuant to the Duquesne RFP. In order to move power from Duquesne to points west, it must move through at least one of these control areas. An entity moving power out of Duquesne's system therefore would need to pay for not only transmission across the Duquesne system, but also across the systems of these entities. As a result, a bidder looking to move power from Duquesne's control area to a point several control areas away would need to secure transmission contracts with each control area operator.

Q. Can you estimate the resulting costs?

A. Yes. Bidders would have to be prepared to pay "pancaked" transmission access charges to Duquesne and to all involved control areas. This would add additional cost and uncertainty, effectively depressing the bid price. Mr. Marshall, Duquesne's President and CEO, discussed this very problem in his testimony in favor of a POOLCO model. His methodology for quantifying transmission charges, and the effect on delivery prices, demonstrates precisely why Duquesne's RFP resulted in depressed bid prices. For example, to be conservative we can use the estimate of a

witness sponsored by West Penn in its restructuring proceeding, Howard Pifer, of $2/MWh for transmission access across each control area and the Marshall estimate of 3% losses. West Penn Power Co., Docket No. R-00973981, Testimony of Hoard W. Pifer III, Statement No. 6, p. 10 and Exh. RBW-16. If a bidder had to cross through a single control area outside Duquesne, its delivered price for 19 $/MWh power in 1999 would be 23.8 $/MWh, while transmitting across two control areas would be 26.5 $/MWh, and three would be 29.3 $/MWh. These values are similar to Mr. Marshall's observation that PJM and ECAR's refusal to provide a truly comparable transmission service to Duquesne raised the effective transmission service charge to potential markets by about 9 $/MWh, which would convert 21.1 $/MWh into 30.1 $/MWh delivered.

Q. Does FERC Order 888 assure transmission access if a buyer is willing to pay the appropriate tariff?

A. No. The physical availability of transmission capacity has not necessarily changed because of these regulatory initiatives. Moreover, Duquesne itself indicated that firm transmission is difficult to acquire, particularly for loads moving west to east: "Duquesne was unable to market long-term capacity to buyers in PJM because of the uncertainty of transmission delivery." *See* Exh. RBW-16. These uncertainties would either depress bid prices or discourage bids in Duquesne's RFPs for power delivered within Duquesne.

Further, given that capacity is constrained on lines moving west to east, a bidder on a "take or pay" contract hoping to move power from ECAR to PJM would bid down the price to account for this uncertainty and risk. Moreover, transmission access pricing for a PJM ISO has been controversial, which adds regulatory uncertainty to the pricing issues. Because the "take-or-pay" contract provision places a premium on predictable access and costs, a purchaser looking to serve load in PJM would have to bid at a level that would recognize these risks, unless it already had sufficient transmission capacity under contract. In any event, this circumstance would both limit the bidder pool and the price any entity would bid.

Take-or-Pay Implications

Q. How does the fact that the contract has a "take or pay" provision interact with the issue of reliance on as available transmission capacity ?

A. A "take-or-pay" provision in a contract requires that the purchaser pay for the power whether or not it takes delivery of the power. Purchasers view this as an additional risk they must incur and therefore would bid down the price. A winning bidder has effectively committed to 75% of the winning bid price regardless of how much power could be delivered to their market. For example, if a bidder agreed to pay $19/MWh with a 75% take or pay, but only expected to be able to deliver the power 50% of the time, the resulting effective price of the power would be 28.5 $/MWh (before transmission and ancillary service charges); effectuating delivery 66.6% of the time would translate into 21.4 $/MWh (before transmission and ancillary service charges).

Combining this "take-or-pay" factor consideration with transmission charges and assuming Duquesne effectively removes the impact of the "take-or-pay" charges for interruptions within it transmission system, a 66.6% predicted availability would result in 26.8 $/MWh after wheeling across one control area, 29.8 $/MWh for across two control areas, and 33.3 $/MWh for across three control areas.

Q. Is Duquesne's 75% "take-or-pay" requirement consistent with maximizing bidders' interest?

A. No. One set of examples has been furnished by West Penn's unregulated affiliate. The affiliate indicated that it had submitted bids in response to RFPs which involved significant flexibility in terms of the capacity bid. In one instance, the bid involved 10-30 MW; another 15-22 MW; another "up to 75 MW;"a fourth varied from 7 MW one year to 18 MW the next; another, 17 MW one year and 71 MW the next. Exhibit RBW-17. Of course, the fluctuations in capacity involved in such RFPs far exceed the range that could be accommodated by Duquesne's 75% take-or-pay requirement or the requirement of a uniform MW bid for all eight years.

Q. Are there other constraints on the value that would be realized by Duquesne's RFP in 1997?

A. Yes. Other utilities may not allow retail access contemporaneously (thereby reducing potential markets for the electricity that Duquesne offered and will offer for sale).

Moreover, utilities may be motivated to use the depressed price to claim artificially high stranded costs which preclude effective competition.

Q. What is your conclusion about the results of the Duquesne solicitation and its usefulness in terms of establishing retail market value?

A. Duquesne ran a solicitation for energy only. The value of power in these solicitations was limited by both the design and the terms and conditions of the solicitation. For example, the resulting price is for power at a Duquesne busbar. Any purchaser would develop their bid by estimating the value of power for specific applications in specific markets and then incorporate a variety of factors to netback to a bid price to Duquesne. Some of these factors are the costs of transmission service and any associated ancillary services. Other factors are the accessibility of firm transmission capacity between the Duquesne busbar and the ultimate market relative to the "take-or-pay" commitment level. The total value of the delivered power is equal to the cost of the expected delivered energy plus the cost associated with transmitting that power to a delivery point and the ancillary services necessary to support the transaction. Using this energy cost as the proxy for market clearing prices in ECAR is, therefore, incorrect. Duquesne is located at one end of ECAR. It would be incorrect to assume that the clearing price in the Duquesne service territory is equivalent to the clearing price in all of ECAR or PJM; rather it is measure of netback to Duquesne when it attempts to sell incremental power on a firm basis into ECAR.

Q. What is your conclusion concerning the market value of Duquesne's assets?

A. Based on the economics of Duquesne's sale of its interest in Ft. Martin, and specifically the valuation that APS placed on that plant's production, and the studies by Duquesne and its financial advisors conducted through November 1996, there is strong evidence that the value of Duquesne's assets far exceeds its net book investment in those plants. Further, the results of Duquesne's RFP in no way refutes or diminishes the significance of the evidence. As a result, I have not found any support for Duquesne's claim that it has any level of stranded costs now or that it will have stranded costs on January 1, 2006.

IV. DUQUESNE'S PROPOSAL TO MAINTAIN ITS CURRENT RATES WOULD IMPOSE ENORMOUS, UNWARRANTED COSTS ON DUQUESNE'S RATEPAYERS

Q. Please provide a brief summary of Duquesne's rate proposal.

A. Duquesne claims that it is entitled to "continue to charge rates each year at current levels so long as it uses any potential excess revenues to accelerate the depreciation and amortization of stranded costs." Clayton, Duquesne Statement No. 2 at 28:13-15. Thus, Duquesne proposes to keep its rates at current levels through the year 2005. Duquesne refers to its proposal as a request to set a "rate cap."

Q. Does Duquesne propose any conditions under which the rate cap would terminate prior to 2005?

A. Duquesne proposes two conditions that could trigger an early end to the rate cap. Clayton, Duquesne Statement No. 2, 41:8 - 44:5. However, in the absence of those two conditions, Duquesne "proposes to extend the rate cap beyond 2005 to recover any stranded costs which will remain after 2005 . . ." Clayton, Duquesne Statement No. 2, at 41:4-5. Duquesne also reserves the right to raise its rates above the rate cap. Clayton, Duquesne Statement No. 2, at 44:7-8. Thus, Duquesne's use of the terminology "rate cap" is a misnomer; Duquesne's proposal more appropriately should be referred to as a request to set a "rate floor" or minimum rate. Viewed in that context, it is apparent that Duquesne's proposal will deny Duquesne's customers rate relief and the benefits of competition through the year 2005, or longer.

Q. Do Duquesne's exhibits provide any evidence to support your contention?

A. Yes. Mr. Lahtinen sponsored Exhibit JAL-4 to show that customers that continue to purchase electricity from Duquesne will be billed the same total amount under Duquesne's unbundled rates that they would have paid under Duquesne's bundled rates. *See, e.g.*, Lahtinen, Duquesne Statement No. 5, at 29:7-11. Thus, Exhibit JAL-4 shows that at a minimum, Duquesne's plan is that its customers should not obtain any rate reduction during the transition period. However, when considered in conjunction with Mr. Clayton's statements to which I just referred, Exhibit JAL-4 also shows that Duquesne's customers could be charged higher rates then they currently pay should Duquesne seek a rate increase, as it reserves the right to do. I

also would note that Duquesne could be viewed as currently attempting to impose a rate increase.

Q. What is the basis for stating that Duquesne could be viewed as attempting to raise its rates?

A. In connection with the sale of its interest in the Ft. Martin Power Station, Duquesne agreed to cap its energy cost rate ("ECR") at 14.7mills/kwh. The Commission approved Duquesne's sale of its interest in Ft. Martin and, among other things, approved the 14.7mill/kwh ECR cap. However, because the ECR prior to that time was 12.822 mill/kwh, the approval of the higher 14.7mill/kwh cap, in effect, gave Duquesne more "headroom" to support higher rates than previously had been in effect. Mr. Lahtinen refers to that fact when he states, the "new unbundled rates are designed to be *revenue* neutral (adjusted for the ECR roll-in)." Lahtinen, Duquesne Statement No. 5, at 8:6-7. That is another way of saying that the ECR roll-in provides for an upward adjustment to Duquesne's prior rates. Therefore, Duquesne's proposal to keep its rates at current levels means the current higher level that results because of the higher ECR.

Q. What statutory basis does Duquesne rely upon to keep its rates at the current level, adjusted for the ECR roll-in?

A. Duquesne relies upon Section 2804(4)(v) of the Act. That section provides as follows:

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

See, e.g., Clayton, Duquesne Statement No. 2, at 27:11-25.

Q. Does Duquesne describe its understanding of the conditions under which that statutory provision allows a utility to continue to charge its current rates?

A. Yes. According to Duquesne, "Section 2804(4)(v) contemplates an approach under which a utility can continue to charge rates at current levels if it can support such rate levels with its test year revenue requirement calculation plus an annual depreciation and amortization of stranded costs." Clayton, Duquesne Statement No. 2, at 28:10-12.

Q. How does Duquesne determine a test year revenue requirement sufficient, in its view, to support its current rate level, adjusted for the ECR roll-in?

A. Duquesne employs two primary mechanisms to provide a purported cost basis for maintaining its current rates, adjusted for the ECR roll-in. First, Duquesne accelerates depreciation and amortization by approximately $1.7 billion. Second, Duquesne exaggerates its cost of service (1) by projecting excessive capital additions for generation, transmission and distribution of over $900 million during the period through 2005 (*See* Exhibit DJC-3, pp. 25 and 28) and (2) by maintaining its inflated O&M expenses. Both mechanisms prop up the revenue requirement to a level in excess of the revenue requirement that would be determined in the absence of the use of those mechanisms. In other words, Duquesne is using the mechanisms to achieve an inflated revenue requirement which in turn produces inflated rates. However, Duquesne does not satisfy the criteria that Duquesne itself sets forth as the requirements it has to satisfy to be entitled to charge those rates.

Q. What criteria does Duquesne state it has to satisfy to be entitled to continue to charge its current rates?

A. According to Duquesne, under Section 2804(4)(v), whatever its total stranded costs may be, a "utility can continue to charge rates each year at current levels so long as it uses any potentially excess revenues to accelerate the depreciation and amortization of stranded costs." Clayton, Duquesne Statement No. 2, at 28:13-15. Thus, Duquesne's witness Clayton states that, to be entitled to a rate cap under Section 2804(4)(v), Duquesne must make a *prima facie* showing that:

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

Clayton, Duquesne Statement No. 2, at 29:1-8.

Similarly, Duquesne's witness Schnitzer states that:

> To make the case for holding rates at the capped levels throughout the Transition Period, Duquesne must make a *prima facie* showing of two propositions. The first is that a mechanism exists to ensure that if revenues under the rate cap are greater than the normal cost of service, these "excess earnings" will be utilized to mitigate transition or stranded costs for the benefit of ratepayers.
>
> * * * * * * *
>
> The second required showing is that the "excess earnings" available under the price cap to mitigate stranded costs are less than or equal to the stranded costs that need to be recovered. Thus, to make this additional showing, Duquesne must demonstrate that stranded costs still remain in 2006 even after the "excess earnings" mitigation or, put another way, that the market value of generation beginning in 2006 is still below the book value of generation and generation-related regulatory assets net of all mitigation during the price cap period.

Schnitzer, Duquesne Statement No. 3, at 22:4-17.

Q. How does Duquesne claim to satisfy the first of its two required showings?

A. Duquesne contends that to be entitled to continue to charge its current rates, it need not show that it has a specific quantification of its stranded costs as of January 1, 1998. *See, e.g.*, Clayton, Duquesne Statement No. 2, at 28:10-15. Rather, Duquesne apparently believes that its unilateral "commitment" to accelerate depreciation and amortization and/or offer its ROE spillover mechanism satisfies the first criterion. I have problems accepting Duquesne's proposition.

Q. What are the problems?

A. Under Duquesne's formulation of the first criterion, there is a representation that the accelerated depreciation will be used to offset stranded costs. As a consequence, there is a inherent assumption that there are stranded costs that the accelerated depreciation will be used to offset. However, as I have already discussed, Duquesne's application does not make any claim to have stranded costs in any specific amount nor does Duquesne claim to know what the net present value of its stranded costs will be at the beginning of the transition period. Exhibit RBW-19. Further, as the discussion in Section III shows, there is substantial evidence that the market value of Duquesne's generation assets significantly exceeds Duquesne's net book investment. Thus, the initial problem I have with Duquesne's proposal is that if Duquesne gains "excess earnings" under its proposed rate cap, it will not offset stranded costs. Rather, the excess earnings will provide a windfall to Duquesne's shareholders.

Q. Will you please describe more specifically the second showing that Duquesne states it must demonstrate to be entitled to continue to charge its current rates?

A. Duquesne's position is that it must show that notwithstanding its acceleration of amortization and depreciation, it will have stranded costs in 2006. An example of that position is contained in Mr. Schnitzer's testimony where he states, "an estimation of the amount of mitigation that can be achieved under the price cap and an estimate of the range of stranded costs remaining as of January 1, 2006 are necessary to satisfy the conditions of Section 2804(4)(v)." Schnitzer, Duquesne Statement No. 2, at 23:3-5. Duquesne's August 1 filing purported to make the latter showing by claiming (based upon Mr. Schnitzer's prediction of market prices), that Duquesne "likely [will] have remaining stranded costs of $8 to $582 million at the end of 2005, depending on the level of market prices in 2006 and beyond." Clayton, Duquesne Statement No. 2, at 29:16-22. As I discussed in Section III, and as the additional reasons discovered below will show, Duquesne clearly has not demonstrated that it will have stranded costs remaining in 2006. Therefore, Duquesne has failed to make its second requisite showing.

Q. What are the additional reasons you have for stating that Duquesne has failed to demonstrate that it will have remaining stranded costs in 2006?

A. There are two bases for that position. The first is that Duquesne's post-2005 quantification of stranded costs is based upon the very methodology for calculating stranded costs, *i.e.*, projected net book investment in 2006 based on the net present

value of the difference between predictions of its long-term costs of generation and predictions of long-term future market prices, that Duquesne itself correctly criticized as being inherently unreliable. The second -- and even more compelling -- reason for concluding that Duquesne failed to demonstrate that it will have remaining stranded costs in 2006 is Duquesne's belated admission that it overstated its Net Present Value of its generating plant assets as of December 31, 2005 in its August 1, 1997 application, and that as a result, it is not certain that Duquesne will, in fact, have any remaining stranded costs in 2006. To the contrary, Duquesne now has calculated that its generation assets may have positive market value of $233 million in 2006. Thus, Duquesne no longer can rely upon its assertion that it will have at least $8 million in remaining stranded costs in 2006 as a basis to show that it satisfies the second of its required showings, because it has calculated itself -- and now acknowledges -- it might not have any remaining stranded costs, at all.

Q. Before discussing Duquesne's new calculations, will you discuss more fully your first point, *i.e.*, that Duquesne relies upon the same methodology that it criticized in its testimony?

A. In its testimony, Duquesne expressed a strong view that predictions of future market prices are inherently unreliable and cannot be used as a basis to calculate stranded costs. For instance, Duquesne's President and Chief Executive Officer criticized forecasts of future market prices stating:

> the uncertainty inherent in such projections poses significant risks for both investors and consumers and cannot be consistent with the known and measurable standard.

Marshall, Duquesne Statement No. 1, at 14:13-14.

And, Duquesne's witness Schnitzer, who ironically sponsors forecasts of future market prices, stated that:

> determination[s] of future market prices based on inherently uncertain predictions about producer and consumer behavior and forecasts of future events or trends cannot, by definition, establish known stranded costs.

Schnitzer, Duquesne Statement No. 3, at 3:16-18.

Schnitzer further pointed out, quite correctly, that "forecasts are highly sensitive to the initial assumptions chosen by the analysts making the forecasts." Schnitzer, Duquesne Statement No. 3, at 9:1-2. He then set forth approximately six pages of testimony to show the folly of relying on forecasts of market prices, and concluded that

> [c]onsumer advocates are rightly concerned that if the forecast of market prices is set too low, and utilities effectively own the generation independent of any obligation to serve following the Transition Period, then any upside value will accrue to shareholders. This is the articulated fear that customers will "pay twice" for generation: once through the CTC charges and again in the form of higher market prices following the Transition Period.

Schnitzer, Duquesne Statement No. 3, at 17:15-16. Notwithstanding that testimony, Duquesne then forecast future electric prices and generating costs up to 2002, Schnitzer contended that the difference between these two forecasts establish that as of January 1, 2006, Duquesne still will have remaining stranded costs *i.e.*, in a range

of $8 million to $582 million. As a result, my first reason for saying that Duquesne fails to satisfy its own articulated criterion is that Duquesne's attempt to satisfy that criterion by relying upon a methodology for calculating stranded costs effective January 1, 2006 that Duquesne amply and correctly showed cannot be relied upon. For that reason alone, Duquesne failed to satisfy its own test.

Q. What is your basis for saying that Duquesne relied upon a forecast of future market prices, and thus upon the same methodology that it criticized?

A. Mr. Schnitzer's own testimony describes the process he used to forecast future prices. Thus, one need only review Schnitzer's testimony to verify that Duquesne's post-2005 stranded cost estimates rely upon Schnitzer's predictions of future prices.

Q. Will you please describe the testimony to which you are referring?

A. Schnitzer stated in his testimony that the market value of Duquesne's generation beyond 2006 was projected by Clayton "based on a range of ceiling market prices that I . . . developed based on the cost of new entry beyond 2005." Schnitzer, Duquesne Statement No. 3, at 25:11-12. He then stated that he "developed an upper bound range of market prices based on the cost of entry by new construction *assuming* that such entry is in fact economic in 2006." Schnitzer, Duquesne Statement No. 3, at 25:16-17 (emphasis in original). Schnitzer further stated that he assumed the technology of choice for new entrants in 2006 will be gas-fired combined cycle units. Schnitzer, Duquesne Statement No. 3, at 26:5-11. Based upon that assumption, Schnitzer "prepared a gas price forecast consistent with current

forward market prices for natural gas . . . [which he] adjusted . . . to create a risk adjusted present value equivalent spot price stream in 2005 . . . [and he] assumed that the price of natural gas would escalate beyond 2005 at the general rate of inflation." Schnitzer, Duquesne Statement No. 3, at 26:13-18. Schnitzer further described how he made assumptions concerning "projected basis differentials between Henry Hub and delivery to a new facility located in ECAR" to account for transportation of natural gas. Schnitzer, Duquesne Statement No. 3, at 27:2-6. He then described additional assumptions he made concerning capacity factors, capital structure, O&M expenses, A&G expenses, heat rates and time horizon for recovery of equity capital and repayment of debt. Schnitzer, Duquesne Statement No. 3, at 27:14-30:4. Based upon all of those assumptions, Schnitzer predicted that future market prices for electric generation will be in a range from $34/MWh($2006) to $44/MWh($2006). Schnitzer, Duquesne Statement No. 3, at 27:8-13; *See also* Exhibit MMS-2. It is against those predicted market prices that Clayton compared Duquesne's costs to determine the market value of Duquesne's generation assets in 2006 and Duquesne's claimed post-2005 stranded costs.

Q. Can you show that Mr. Clayton incorporated forecast assumptions into his calculations?

A. Yes.

Q. Will you please describe what leads you to that conclusion?

A. Yes. For example, Statement 2, Exh. DJC-3 contains over 67 pages of computer print outs containing assumptions for fuel costs, O&M costs, overhauls, taxes and capital expenditures on a year-by-year basis from 2006 up to 2026. Therefore, there is no room to debate that Schnitzer, Clayton, and ultimately Duquesne, relied upon the same flawed methodology for claiming stranded costs that Duquesne so heavily criticized as being unreliable. Further, as I will discuss in Section VII, Duquesne's price predictions are no more reliable than computer-generated price predictions by others. I will show that Mr. Schnitzer input unreasonable assumptions into his own computer spreadsheet which resulted in the unreasonably low price predictions Duquesne relies upon in this case. I also will show later in this section that Mr. Clayton's assumption concerning capital additions, and O&M expenses are inflated which will further inflate stranded costs.

Q. Does the fact that Duquesne provided a range of potential post-2005 stranded costs show that its price predictions and stranded cost claims should be accorded more weight than the price predictions and stranded cost claims that Duquesne criticizes?

A. No. In fact, Duquesne's October 16 revisions prove that Duquesne's prediction of a high and low range of stranded costs is as inherently unreliable and unacceptable as an attempt to pinpoint a specific stranded cost claim when the consequence is to impose billions of dollars of stranded cost liabilities on consumers. Further, it is Duquesne's October 16 revisions that provide the most compelling reason to

conclude that Duquesne failed to satisfy the very criteria that it acknowledged it had to satisfy to be entitled to be granted its rate proposal in this case.

Q. Will you describe your basis for that conclusion?

A. Duquesne's unequivocal position in claiming that it qualifies to continue to charge its current rates, adjusted for the ECR roll-in, under Section 2804(4)(v) was based on its contention that as of January 1, 2006, it would have some amount of stranded costs remaining. As Schnitzer said, "Duquesne has . . . shown that it cannot fully recover its stranded costs through application of "excess earnings" through 2005 under the rate cap." Schnitzer, Duquesne Statement No. 3, at 46:11-13. He was referring to the fact that, as a result of his predictions of future market prices, Clayton had determined that Duquesne would have a minimum of $8 million in stranded costs remaining as of December 31, 2005. However, on October 16, Duquesne corrected its previously fixed cost data because it learned it had *overstated* its net generating plant assets at the end of 2005 in its August 1 filing. Duquesne determined, based upon the corrected data, that the estimated market value of Duquesne's generating assets is higher than Duquesne previously had represented, and as a direct consequence, its prior estimate of stranded costs should be reduced. Exhibit RBW-1. Thus, when Duquesne measured Schnitzer's predictions of future market prices against Duquesne's corrected cost data, Duquesne determined that, at a maximum, it might have $423 million in remaining stranded costs as of January 1, 2006. However, Duquesne also recognized that it might have positive market value of $233 million. *Id.* Thus, using Duquesne's own calculations, it is beyond dispute that there

are a range of circumstances under which Duquesne admits that "the market value of generation beginning in 2006 [will be above] the book value of [Duquesne's] generation and generation-related regulatory assets net of the committed minimum level of depreciation and amortization." *See* Marshall, Duquesne Statement No. 1, at 29:7-8. Similarly, using Duquesne's own calculations, it is beyond dispute that "Duquesne has . . . shown that it [can] fully recover its stranded costs . . ." if Schnitzer's high future market price becomes reality. Therefore, one need only examine Duquesne's own revised calculations to determine that Duquesne does not satisfy the second criterion that Duquesne stated unequivocally it had to satisfy to qualify to be granted the right to continue to charge its current rates, adjusted for the ECR roll-in, under Section 2804(4)(v).

Q. Assuming that Duquesne does not qualify for the rate cap, what is the consequence of Duquesne's proposal to accelerate depreciation and amortization by $1.7 billion?

A. The consequence is that approval of Duquesne's proposal will allow Duquesne to recover a significant portion of its investment in generation plant on an accelerated basis prior to the commencement of true competition. That consequence will aid Duquesne substantially by reducing its cost-profile to enable it to compete more effectively post-2006. However, Duquesne's ratepayers will suffer by being required from 1998 through 2005 to pay rates higher than would be appropriate without the accelerated depreciation. In other words, the accelerated depreciation will assist Duquesne in propping up its rates to levels that would be too high under traditional

ratemaking methodologies. That is particularly inappropriate here because Duquesne has not shown that its "excess earnings" will offset stranded costs, as opposed to provide an unwarranted windfall to Duquesne's shareholders.

I also would point out that allowing Duquesne to accelerate depreciation will disadvantage current competitors and those competing in the post-2006 period. That is because potential new entrants to the market will be forced to compete against an entity that gained an unwarranted advantage in using the regulatory process artificially to reduce the costs against which the new market participants must compete. Duquesne's competitive advantage will benefit Duquesne's shareholders, but provide no commensurate benefit to consumers. After all, in the unregulated world, Duquesne will capture the benefit of its below-market cost profile for its shareholders, not its customers.

Reasonableness of 1987 to 1996 Capital Additions

Q. You stated earlier that Duquesne also is using other mechanisms to prop up its rates, particularly projected capital additions and O&M expenses. Will you first discuss your reasons for reaching that conclusion with respect to Duquesne's projected capital additions?

A. For one thing, it cannot be overlooked that Duquesne has not filed a base rate case since 1986. As a result, the Commission never has found that Duquesne's post-1986 capital expenditures were reasonable. Thus, Duquesne's past capital expenditures

which it includes in its calculation of rate base may be inflated or include amounts that are unreasonable.

Q. What are Duquesne's total capital expenditures since its last rate case?

A. Data taken from Duquesne's FERC Form 1 reports show that between 1987 and 1996, Duquesne's generation-related capital expenditures were approximately $382 million. Those expenditures exclude amounts related to Duquesne's Beaver Valley 2 unit and its initial capital expenditures of $743 million for Perry Unit 1. Duquesne's distribution-related capital expenditures during that same time period were approximately $473 million. Duquesne's transmission-related capital expenditures were approximately 62 million. Therefore, Duquesne's total capital expenditures since its last base rate case were approximately $917 million.

Table IV-1 - Past Capital Expenditures

Year	Generation	Distribution	Transmission
1987	$84,506,175	$35,225,146	$15,241,735
1988	40,075,039	39,321,272	(365,258)
1989	29,006,877	41,078,506	3,776,864
1990	35,228,079	47,420,621	3,029,054
1991	27,107,618	52,198,652	3,437,120
1992	27,812,672	52,792,305	17,060,327
1993	41,504,296	42,281,236	3,874,062
1994	45,815,702	47,067,648	596,816
1995	30,350,883	33,733,176	1,037,070
1996	20,394,132	36,507,416	7,285,402
Total	$381,801,473	$473,073,035	$61,803,132

Q. Has Duquesne submitted testimony or exhibits in this case to demonstrate that those expenditures were reasonable?

A. No. Duquesne's rates are designed by including those expenditures in rate base, but I am not aware of any testimony Duquesne has submitted to justify those costs.

Q. Has anyone to your knowledge questioned the reasonableness of Duquesne's expenditures since its last rate case?

A. Yes. Ironically, Duquesne's merger partner, West Penn, questioned those expenditures in Docket No. C-00967749. In that case, West Penn's witness noted that Duquesne's last rate case was concluded in 1988. He also testified that, referring to Duquesne's costs, "Duquesne is either extremely inefficient or is over-recovering.

Because electric service is still bundled, it is difficult to tell if Duquesne's rate is reasonable for any single component of electric service." Exh. RBW-20.

Q. Why is the issue of Duquesne's past capital expenditures important to consider in the context of analyzing whether Duquesne should be permitted to continue to charge its current rates?

A. Duquesne's past capital expenditures obviously must be considered in the context of determining whether Duquesne's proposed rates are reasonable. To the extent the Commission cannot determine the reasonableness of Duquesne's past expenditures for capital additions because Duquesne (1) unilaterally chose not to file a base rate case since 1986 and (2) failed to submit evidence in this case to support the reasonableness of its past expenditures, those are factors the Commission should consider in its determination of whether Duquesne's rate proposal is reasonable given that the proposal is based in substantial part on those past expenditures being included in the rate base.

Projected Capital Additions

Q. Is there another issue that concerns Duquesne's capital expenditures in relation to its rate proposal?

A. Yes. Duquesne also has projected substantial capital additions for generation and distribution. Duquesne forecast those capital additions for some of its generation plants as far out as 2026, or nearly 30 years into the future. Its rate proposal

implicitly relies upon the capital additions through 2005. Moreover, to calculate its stranded cost claim, Duquesne accounted for generation-related projected capital additions by determining what they would be as of December 31, 2005 on a net present value basis. Thus, Duquesne's claim that it might have stranded costs as of that date expressly is based upon Duquesne's inclusion of the projected costs of those capital additions.

Q. What is the magnitude of Duquesne's projections of the costs of its generation-related capital additions?

A. Duquesne estimates that it will expend $352 million in capital additions from 1997 to 2005. Exh. DJC-3, at 25.

Q. What is the magnitude of Duquesne's projections of the costs of its distribution-related additions?

A. Duquesne estimates that it will expend $532 million in capital additions from 1997 to 2005. Exh. DJC-3, at 28.

Q. What is your opinion of those projections?

A. Duquesne's projections are excessive, and its projected expenditures are not known or reasonable. Duquesne cannot accurately forecast its capital expenditures even one year in advance, much less almost thirty.

[PROTECTED MATERIALS WITHHELD PAGES 59-61]

Q. Given that you conclude that Duquesne's capital addition projections are excessive and do not meet the known and measurable test, what is your recommendation for capital additions in relation to Duquesne's proposed rates?

A. I would reduce Duquesne's projected generation plant capital additions by 20% and Duquesne's projected distribution plant capital additions by 10% which would reduce Duquesne's projected capital additions over the period 1997 through 2005 by $71 million on a net present value basis.

Exaggerated O&M Expenses

Q. Have you performed any other analyses to determine whether or not Duquesne's estimates of future O&M costs are reasonable?

A. Yes. I have compared Duquesne's historic production costs to those of other utilities in ECAR as well as in Pennsylvania using data from benchmarking studies performed by Standard & Poor's Rating Information Services (Exh. RBW-23) and Barakat and Chamberlin, Incorporated (Exh RBW-24). I have also reviewed similar benchmarking studies commissioned by Duquesne (Exh RBW-25), and statements by Duquesne in recent annual reports.

Q. What have you concluded from this analysis?

A. From these studies, it appears that Duquesne has been making progress towards reducing its production and operation costs, but that it is still below ECAR regional averages in numerous categories. For example, based on information provided in the

Standard & Poor's study, Duquesne's total energy costs were 15% higher than the ECAR average for 1995 and its fixed production costs were 40% higher than the ECAR average. These cost components contribute to a total production cost that was 20% higher than the ECAR average for 1995. These results are supported by an analysis conducted by Barakat and Chamberlin, Inc., which ranked the relative efficiency of 94 utilities nationwide. Based on this study, Duquesne ranked in the bottom third and scored the worst of any of the ECAR and Pennsylvania utilities included in the study. For example, according to the data used in the Barakat and Chamberlin study, Duquesne is the most inefficient utility in its region with regard to the number of MWh generated per employee. Even Duquesne's own research finds that Duquesne is underperforming relative to industry standards. In a study for Duquesne, Metzler Associates found that Duquesne could reduce plant operations personnel by 45% by adopting industry best practice. Exhibit RBW-4.

The industry is transitioning to a competitive environment and Duquesne has indicated to its shareholders that it is intent on competing: "We welcome it [competition] . . . . DQE is an evolving energy services company that is strategically positioning itself to meet the expanding needs of the marketplace." (*See* 1996 Annual Report to Shareholders.) Duquesne has stated that they have taken steps towards streamlining operations and positioning itself for competition by selling assets and reducing its workforce (the following from 1996 Annual Report to Shareholders)

On October 31, 1996, Duquesne Light completed the sale of its interest in Ft. Martin Power Station.

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Duquesne Light continues to focus on quality customer service and enhanced operation efficiencies

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On November 6, 1996, Duquesne Light bargaining unit employees ratified a three-year contract extension, through the year 2001

Despite these efforts, Duquesne's production costs are higher than most every utility in ECAR. If they are intent on competing, as they have stated, then in order to be successful, Duquesne would have to implement programs that, at a minimum brought them to the regional average with regards to production and operation expenses. Doing this would reduce going forward costs by approximately 15%. Therefore, Duquesne should account for savings that are likely to be achieved as a result of operating in a competitive, more entrepreneurial environment.

Q. Do you have an alternative rate proposal that corrects the problems you have identified with Duquesne's rate proposal?

A. Yes. **[PROTECTED MATERIALS WITHHELD]**

V. MITIGATION IN THE ADMINISTRATIVE PROCESS

Q. Can you summarize potential prospective sources of mitigation?

A. Utilities have an ongoing duty to take all practicable measures to mitigate stranded costs. Such measures can include reduction of expenses, renegotiation of contracts, refinancing of debt, sale of generation assets, write-offs and retirements and rate reductions.

Q. Why is full mitigation important?

A. Full mitigation will reduce costs for ratepayers, a primary goal of industry restructuring. Less than full mitigation subsidizes the utility, providing it with an unfair advantage in newly competitive markets.

Q. Has Duquesne actively pursued full mitigation?

A. Not fully. Although Duquesne has taken steps towards mitigating costs, there are additional measures that could be pursued. For example, Duquesne pursued the sale of its interest in the Ft. Martin Plant for which it received a price more than four times greater than Duquesne's net book interest in the plant. It has not, however, pursued the sale of its other generating assets, despite its own studies, and reports from its consultants and financial advisors, that indicate that Duquesne, and ultimately its ratepayers, would realize significant benefits from such a sale. *See* Section III, above. As I previously discussed, the conclusion to be drawn from those studies and reports is that Duquesne's sale of its assets would produce returns well

in excess of Duquesne's net investment and, in fact, would offset all of Duquesne's claimed stranded costs. Therefore, Duquesne should be encouraged to explore all opportunities, including through financial incentives established in this proceeding.

Q. Should Duquesne's failure to pursue available mitigation strategies affect the Commission's review?

A. Yes. As Duquesne has informed investors,". . . the PUC expects utilities to take vigorous steps to mitigate transition costs as much as possible without increasing the price they currently charge customers. The PUC will determine what portion of a utility's remaining transition costs will be recoverable from customers through a CTC" (see page 39 of Duquesne's 1996 Annual Report to Shareholders). Therefore, if Duquesne's management does not actively pursue all mitigation strategies, the consequences should be Duquesne's responsibility, not its ratepayers', and the Commission can ensure that result through remedial actions.

A. Correcting For Duquesne's Premature Plant Closing Assumptions

Q. Has Duquesne neglected to analyze an important means of mitigating stranded costs?

A. Yes. Duquesne should have considered the benefit that could result from extending the life of certain plants to create positive cash flow. When low cost plants are operated over longer periods, their below-market costs can offset greater amounts of above market costs.

Q. Describe how the dates presumed in Duquesne's computer simulations for the closing of various generating plants affect the magnitude of stranded costs?

A. Duquesne claims that some of its plants will generate electricity at costs above market clearing prices. I will refer to those plants as the "non-competitive plants." Duquesne claims that other plants, which I will refer to as its "competitive plants," will produce electricity at costs below market clearing prices. Sales of electricity from the competitive plants can offset the stranded costs associated with the non-competitive plants. Therefore, the longer the competitive plants operate, the greater the offset against stranded costs. Conversely, the longer the non-competitive plants operate, the higher the stranded costs. As a result, the retirement dates presumed in Duquesne's simulation for the competitive plants and for the non-competitive plants directly effect Duquesne's net stranded costs.

Q. When does Duquesne's estimation of stranded costs assume that a generating facility ceases operation?

A. Duquesne assumes that when a facility's cost has been fully recovered for ratemaking purposes, that facility will cease operation regardless of the value of its power. Of course, some plants could continue generating electricity for years after the date of full recovery of depreciation. It is hard to imagine that a business would neglect to consider "economic retirement." Accordingly, it is unreasonable for Duquesne to calculate its stranded costs based upon a scenario that contravenes operating its facilities in a prudent, economically rational fashion.

Q. How do the retirement dates that Duquesne used in its stranded cost calculations affect the magnitude of stranded costs?

A. Once a plant has been fully depreciated, the portion of the plant's revenues that were previously dedicated to return of invested capital instead can be devoted to other purposes, or the plant can be operated thereafter at a lower cost. As a result, a non-competitive plant could become a competitive plant because of lower total operating costs. Extending operation of the previously non-competitive, but now competitive, plant could produce positive cash flow to offset stranded costs associated with non-competitive plants. Similarly, a plant which already was competitive before becoming fully depreciated only becomes a better tool for offsetting stranded costs when it continues operation after depreciation has been fully recovered for ratemaking purposes.

Q. Do you have an example of how Duquesne could have implemented this mitigation strategy?

A. Yes -- the Sammis plant. In 2010, it generated $30.9 million over and above its direct operating costs assuming Duquesne's "high" market line case. Even though Sammis is contributing significant mitigating positive revenue, Duquesne presumes the plant is shut down in 2010. But if the plant continues operating beyond Duquesne's projection, its operating margin offsets additional amounts of claimed stranded costs. Similarly, the year after the Eastlake plant contributes more than $16 million in mitigation, Duquesne's calculations presume that such an economically

strong unit is shut down. Duquesne's stranded cost calculation fails to reflect the positive cash flow from fully depreciated units, such as Sammis and Eastlake, that could mitigate stranded costs.

Q. Are there other effects upon stranded cost consequences when the retirement date of a generation plant is changed?

A. Yes. By continuing to run the plants, Duquesne defers the date when it must pay decommissioning costs, thereby reducing the net present value of that obligation.

Q. How should Duquesne determine when to retire a power plant?

A. A good barometer of a unit's ability to mitigate stranded costs is the unit's "going forward" costs, *i.e.*, whether the unit could cover its variable and fixed costs, including fuel, operating and maintenance expenses, administrative and general costs, capital additions, and taxes from the market value of its power. If it can, the plant should continue to operate. Otherwise, it should be retired. Obviously, this optimal retirement decision can vary with the assumed value of prices and also the costs of operating the units.

Q. What does this suggest to you?

A. This suggests that Duquesne is assuming the premature retirement of these units.

Q. What effect would premature retirement have on Duquesne's calculation of stranded costs?

A. Premature retirement would tend to overstate stranded costs. If these units continue to operate, there would be additional "stranded benefits" or profits to offset any uneconomic unit.

B. Correcting For Duquesne's Delayed Plant Closing Assumptions

Q. Have you identified any other issues with regard to plant retirements that could effect Duquesne's calculation of stranded costs?

A. Yes, it appears that Elrama, Brunot Island, and Perry should be retired immediately.

Q. What is the basis for this conclusion?

A. Using Exhibit RBW-12 and referring to Exhibit MMS-5, I sought to determine whether each of these units was covering its going forward costs by subtracting fuel-related expenses (including emissions), variable and fixed O&M, capital additions, and an overhead allocation from the energy revenues generated by each of the units.

Q. What conclusion do you draw from that review?

A. If Duquesne believes its own assessment of the going forward costs of those units and the value of power between 1999 and 2005, it can reduce its stranded costs by accelerating the retirement of some of its units.

C. Decommissioning Costs

Q. Are decommissioning costs for fossil plants properly established by Duquesne?

A. No. As discussed above, Duquesne's projected retirement dates of some of its generating units may have to be adjusted to fully mitigate stranded costs and protect the consumer. Duquesne's stranded cost claims for its generating units are predicated on the erroneous presumption that when the utility's investment in a unit has been fully recovered for ratemaking purposes, that unit will be taken out of service and retired.

Q. Are there additional reasons to challenge Duquesne's fossil decommissioning estimates?

A. Yes. The PUC's audit Staff recently tested the Company's property records, and discovered that plant balances were overstated by over $2 million, in part because of unrecorded retirements or due to items not devoted to utility service. Exh. RBW-26. Obviously, decommissioning costs should not be collected from ratepayers for plant already retired or not devoted to utility services.

Q. Did the Staff conduct a comprehensive audit of Duquesne's accounts?

A. No. They were able only to sample approximately 95 work orders out of a list of 350 work orders. Of the 95 work orders reviewed, Staff inquired about 35 and received "either incomplete or unsatisfactory" answers with respect to 25, or more than 25%, of the sampled work orders.

Q. Given this experience, what do you recommend?

A. These circumstances highlight the fact that the Company's activities, investment decisions and expenditures in many instances have not been subject to a base rate case since 1986. As a consequence, I would recommend that Duquesne be required to retain a reputable accounting firm to review the balance of the 350 work orders that Staff did not review and certify that the disposition of amounts comports with the Uniform of System accounts, before Duquesne is permitted to recover decommissioning costs. If the accountants identify any adjustments they believe should be made, Duquesne would have to make such adjustments before becoming entitled to recover any costs pursuant to its filing in this proceeding.

Q. Do you have another recommendation with respect to nuclear decommissioning costs?

A. Yes. Given the complexity of the technical issues surrounding the estimation of decommissioning costs for nuclear plants, I believe that the Commission can improve consumers' protection by establishing a separate audit process. This audit process will assure that the nuclear decommissioning costs that Duquesne proposed in this

proceeding are in fact reasonable. Given the highly specialized nature of forecasting nuclear decommissioning costs, it is reasonable to provide ratepayers with the assurance the Duquesne's assumed decommissioning costs are fair estimated prior to assuring costs recovery through CTC.

Q. How would the audit process work?

A. An independent expert in the field of nuclear decommissioning would be retained by the Commission to perform the audit. This expert would be selected based on input from the Commission ratepayer groups, Duquesne, and other interested parties. Selection of the expert would be completed within 2 months of the Commission's final order in this proceeding. The auditor would complete its assessment of the proposed costs of decommissioning within 3 months of selection. Duquesne and other interested parties would have an opportunity to review and comment on the auditor's report. However, after the comment period, the Commission's decisions regarding the level of nuclear decommissioning costs would be final and that level of decommissioning costs authorized by the Commission would be included in Duquesne's stranded costs.

Q. Who would pay for the independent auditors?

A. The owner of the plants (*i.e.*, Duquesne, in this instance) would pay for the audit.

Q. Who would direct the work of the auditor?

A. The auditor's work scope and deliverables would be assigned by the Commission, since the Commission would be the ultimate recipient of the audit.

Q. Does the utility have an opportunity to obtain additional funds to cover nuclear decommissioning costs if the costs of decommissioning exceed the estimates developed in this proceeding?

A. Yes. The utility may file a rate increase to recover unforeseen increases in nuclear decommissioning costs.

Q. Would ratepayers receive a refund from Duquesne if the actual cost of decommissioning is less than adopted in this proceeding?

A. No. Thus, the risks associated with stranded costs for nuclear decommissioning are borne almost entirely by ratepayers.

Q. What facts influenced your proposal regarding nuclear decommissioning costs?

A. To date, there have only been four completed nuclear power plants that have been decommissioned in the United States. Of these, only one was even remotely similar in size and power output to Beaver Valley 1 and 2 or Perry, (e.g., Shoreham, near Wading River, NY at 2436 MW). Thus, there is almost no established track record associated with decommissioning large-scale utility nuclear power plants. Based upon the absence of prior experience in developing an estimate of decommissioning costs, it is likely that cost proposals from contractors and estimators err on the side

of excessive estimation of costs. On the other hand, a number of nuclear plants are nearing retirement. As a result, the costs of decommissioning may be lower than expected by Duquesne because any new costs will be shared among a number of plant operators.

Q. What is you conclusion based on these circumstances?

A. Because of the stakes potentially involved in nuclear decommissioning, the risk of forecasting these costs is too great for either the utility or ratepayers to bear individually. Additionally, the utility may come back for a second bite at the apple regarding decommissioning costs while ratepayers do not have that option. In order to balance the risks on both side, I recommend that a risk sharing mechanism be adopted by the Commission.

Q. Do you have an additional safeguard to ensure the Company does not receive a windfall from nuclear decommission funding?

A. Yes. In 1994 the Company and other CAPCO participants entered into a settlement with General Electric concerning the Perry 1 GE Mark III reactor. When asked to quantify the award received by Duquesne, Duquesne declined, citing confidentiality. Exh. RBW-27.

Q. How would you propose to recognize this award to Duquesne?

A. At a minimum, the award should be treated as an offset to net utility plant balances. Otherwise, Company will be compensated once for the Perry Unit by General Electric, and again by ratepayers. Moreover, the award was agreed to three years ago. Duquesne will have received the time value of the money from the date on which Duquesne received revenues under the award until the date of any order directing the crediting of such amounts against the plant balances.

Q. Are there possible relevant financial developments from 1994 to date?

A. The PUC Staff's audit of Company books and records identified an "Other Matter of Interest," which showed that unregulated investments surged from $125 million on December 31, 1993 to $518 million in 1996. Exh. RBW-26 at 19.

Q. Please describe your recommendations regarding recovery of stranded costs associated with nuclear decommissioning?

A. Based upon the foregoing circumstances, I recommend that the Commission establish a balancing account to recover actual decommissioning costs. Any increases or decreases in decommissioning costs that arise from a comparison of actual expenditures to the Commission-approved estimated decommissioning cost would be shared by ratepayers and shareholders.

Q. How would the risk be shared among ratepayers and shareholders?

A. I recommend that ratepayers be responsible for 75% of any under- or over-collection of decommissioning costs. This makes utility shareholders responsible for 25% of any forecast error associated with the decommissioning cost estimate that is ultimately adopted by the Commission.

D. Duquesne Could Offer To Reduce Its Rates

Q. Are there other mitigating factors that the Commission should be concerned with in evaluating Duquesne's stranded cost claims?

A. Yes. Typically, a utility files a rate case when its existing rates do not produce revenues that cover its costs. Duquesne has not filed a general rate case in 10 years. Consequently, since 1987 Duquesne found its revenues at least satisfactory *vis-a-vis* its costs.

Q. Have shareholders received a reasonable return on common equity over this period?

A. Yes. According to the 1996 Annual Report to Shareholders, the return on average common equity has increased from 11.1% in 1987 to 13.2% in 1996. Further, Duquesne's representations to the financial community contrast sharply with its claim here that its shareholders have borne the brunt of Duquesne's past mitigation efforts. Clayton, Statement No. 2, at 21:15-19.

Q. What has Duquesne represented to the financial community?

A. Duquesne has portrayed itself as a company with substantial financial strength.

Q. Can you give examples?

A. Yes. For instance, Duquesne made a rating agency presentation in August 1996. In that presentation, Duquesne boasted of having a historical record of "continuous improvement in key financial indicators." RBW-28. It also listed as its financial strengths its low Clean Air Act exposure and reduced capital expenditures. *Id.* It forecast returns on average common equity in the following percents for 1996 through 2000:

Table V-2: Duquesne's Projected Returns On Average Common Equity

Year	1996	1997	1998	1999	2000
ROE	14.6%	15.4%	14.9%	14.3%	14.7%

Excerpts from that presentation are included in my Exhibit RBW-28 (Avg. 1996 Rating Agency Presentation.).

Q. According to Duquesne, how does its financial performance compare to other utilities?

A. Just six weeks ago, in a September 23, 1997 presentation to NatWest Securities, Duquesne boasted that its earnings per share as of the 12 months ending June 30, 1997 were up to 8.4% from the prior 12-month period. It also indicated that its declared dividends were up 6.4%, and its book value was up 6.8%.

In that same presentation, Duquesne showed that from 1993 to 1997, it experienced annual compound growth rates in earnings per share and dividends of 8.0% and

6.2%, respectively. It also boasted that its 5-year growth rates in earnings per share was 6th highest of all ranked utilities; its 5-year growth in dividends per share was 2nd highest of the ranked utilities; and, its payout ratio was lowest of all utilities. Exh. RBW-29.

Q. How do the benefits Duquesne gained for its shareholders compare with benefits it provided to its ratepayers?

A. Like day and night.

In contrast to the benefits it gained for shareholders, Duquesne did nothing to lower its rates. In part, in its rating agency presentation, Duquesne promoted a strategy that anticipated a continuation of its practice of not filing base rate cases RBW-30.

Q. How do Duquesne's rates compare with rates of other utilities?

A. Duquesne's rates are among the highest in the Commonwealth and its average monthly bill to commercial class customers ranked Duquesne the eleventh highest of 150 utilities in the nation.

Q. How does Duquesne describe the methods by which it achieved benefits for its investors?

A. According to Duquesne's 1996 Rating Agency Presentations, it reduced its interest expense 21% from 1992 to 1995. RBW-31. It reduced its staff by 25% since 1983. *Id.* It also reduced its staff from 1990 to 1995 by 19%. *Id.*

Duquesne stated in its rating agency presentation that it also reduced its production costs from 2.56¢/Kwh in 1986 to 2.15¢/Kwh in 1995. *Id.* Additionally, Duquesne claimed to reduce nuclear related O&M costs by over 20% in the three preceding years. *Id.* In its testimony, Duquesne also boasts about savings it has achieved by refinancing debt at lower interest rates and by gaining tax advantages from accelerated depreciation. *See, e.g.*, Duquesne Statement No. 4, at 9:16-17 and Statement No. 2 at p. 10-14.

Q. But doesn't Duquesne claim that ratepayers have enjoyed the savings from those latter two items?

A. That is Duquesne's claim. However, when HSS/ARI asked Duquesne to explain how ratepayers benefited from Duquesne's refinancing efforts and tax advantages, Duquesne's response was that those items "reduce[d] its need for rate increases. . ." Exh. RBW-32. Given that Duquesne's rates, particularly to commercial class customers, already rank it among the highest in the nation and given the financial results it has provided for its shareholders, I would expect that Duquesne might not have been able to justify existing rates, much less increase them. I also suspect it had little motive to do so given that its return on equity in its last rate case was 12.87%.

Q. What mitigation effect do you think would be appropriate in view of the foregoing?

A. Duquesne should consider reducing its rates. As I discussed previously, there is "headroom" for Duquesne to cut its rates as is reflected by the fact that its attempt to cost-justify its rates requires it to accelerate amortization and depreciation by $1.7 billion.

Further, in determining Duquesne's rates in this case, the Commission should apply a greater level of scrutiny to Duquesne's stranded cost calculations than it would to a utility that had filed a general rate case on a recent basis. I have not assumed, and I do not think the Commission should either, that Duquesne's current and projected revenues are closely aligned with costs calculated on a traditional regulatory basis. Of course, Duquesne's willingness to reduce rates is a relevant criterion in assessing whether it has mitigated its claimed stranded costs to the fullest extent reasonably possible.

E. Appropriate Return on Equity

Q. What is the rate of return on common equity ("ROE") that Duquesne has assumed for the determination of its stranded costs?

A. Duquesne's witness Makholm recommended 11.65% as a fair return on equity for Duquesne. Makholm, Duquesne Statement No. 12, at 3:12-13. However, Duquesne's witness Clayton stated that"[t]o be conservative, [he] reduced this

amount to 11.5% as the Company's claimed cost of common equity." Statement No. 2, at 47:2-3.

Q. How is this ROE used in the determination of Duquesne's stranded costs?

A. The ROE was used to determine Duquesne's weighted-average after-tax cost of capital, which was used in estimating Duquesne's revenue requirements over the period 1997 through 2026. It also was used for determining revenue requirements for the same period, which incorporated a return on equity. Duquesne then determined its total revenue requirement on a net present value basis as of 2006.

Q. Is Duquesne requesting that its authorized ROE be set at 11.5%?

A. Not really. Duquesne actually is attempting to obtain a 12% ROE.

Q. What is the basis for that conclusion?

A. Duquesne proposes to establish a ROE spillover mechanism that theoretically could result in an early end to Duquesne's recovery of any CTCs and a final valuation of Duquesne's generation assets. Under the ROE spillover, Duquesne proposes to establish a collar on its earnings of + or - ½% around its claimed ROE of 11.5%. Clayton, Statement No. 2, at 42:14-15. Duquesne proposes that if earnings exceed 12%, it would establish a deferred revenue credit account purportedly to fund accelerated depreciation and amortization. Clayton, Statement No. 2, at 42:15-17.

If earnings fall below 11%, Duquesne would adjust the deferred account to increase Duquesne's ROE to 11%. *Id.* at 42:17-18.

I will explain in Section VIII that the ROE spillover mechanisms is a sham that works only to Duquesne's benefit and that it will not trigger an early end to Duquesne's recovery of any CTCs that might be approved. However, the ROE spillover mechanism also is detrimental to ratepayers in that it masks the fact that Duquesne, in reality, is seeking a 12% ROE.

Q. How does the ROE spillover mechanism increase Duquesne's requested rate of return?

A. The ROE spillover mechanism is designed to produce that result. Under its proposal, Duquesne would have the right to retain earnings that are in excess of 11.5%, but not greater than 12%. Therefore, Duquesne really is seeking authorization for a 12% ROE in this case.

Q. Do you think that either 11.5% or 12% is the correct ROE to use when determining the CTC revenues associated with Duquesne's generation-related assets?

A. No. It is appropriate to reduce the ROE for those assets, given the reduced risk associated with them, *if Duquesne recovers stranded costs pursuant to a CTC or an ITC.*

Q. Why would such circumstances warrant a reduced ROE?

A. First, the enactment of HB 1509 dramatically reduced the risk of stranded cost recovery facing Duquesne by:

- authorizing a non-bypassable CTC charge;
- implementing accelerated depreciation of uneconomic sunk costs;
- establishing balancing accounts for CTC and providing for exceptions to the rate cap for a variety of events that might otherwise negatively impact the state's utilities' ability to recover these costs;
- enhancing utilities' opportunity to recover costs and expenses associated with transitioning to a competitive market; and
- making available irrevocable securitization orders.

Second, under Duquesne's proposal, market prices under the capped rate are extremely low, essentially qualifying a large percentage of Duquesne's going forward and fixed costs for recovery pursuant to the legislatively-mandated, non-bypassable CTC, thereby reducing risk. Moreover, because of the way Duquesne proposes to design individual CTCs, Duquesne is provided a virtual guarantee of 100% recovery of any amount that may be authorized to be recovered as stranded costs.

Q. Have other commissions authorized a reduced ROE in recognition of the reduced risks associated with stranded cost recovery as required by the Act?

A. Yes. This was the approach taken by the California Public Utilities Commission ("CPUC"). The CPUC recognized that restructuring decreased risk by providing a high degree of revenue assurance. As such, utilities deserve a lower return on equity:

> [T]oday's decision decreases the risk associated with recovery of remaining net investment (now part of transition costs), due to the imposition of a nonbypassable charge on distribution customers (as described in greater detail below) which decreases utility business risk. [*see* CPUC Decision 95-12-063, page 124].

Q. What ROE did the CPUC authorize utilities to earn on their unamortized generation assets?

A. The CPUC allowed the utilities to earn a ROE equal to each utility's embedded cost of debt less 10% (*i.e.*, if the embedded cost of debt was 7%, then the ROE on amortized generation assets would be 6.3%). However, if the utilities divested 100 percent of their fossil-fired generating assets, then their ROE would increase to the embedded cost of debt.

Q. What was the CPUC's reasoning for this particular ROE?

A. Prior to this decision, the CPUC had authorized reduced ROE on sunk costs for other generating plants. For example, the CPUC authorized Southern California Edison to earn a return on equity equal to the embedded cost of debt on remaining net investment associated with the retired San Onofre Nuclear Generating Station Unit I and only 90% of embedded debt if it did not divest (*id.*). However, the CPUC recognized that utilities would face even less risk for the recovery of equity after the imposition of a non-bypassable transition charge and that the utilities would need an incentive to attempt to mitigate stranded costs associated with fossil-fired generators.

Q. What would be implied of such an ROE reduction on Duquesne's rates?

A. There would be an annual reduction in revenue requirements of up to $50 million.

F. Merger Benefits

Q. Dr. Weisenmiller, does Duquesne claim that its proposed merger with APS will produce any cost savings that could mitigate stranded costs?

A. Mr. Marshall testified that the proposed merger will result in approximately $550 million in additional mitigation available from cost savings associated with the proposed merger.

Q. Does Duquesne's application here apply that $550 million against Duquesne's stranded cost claim?

A. No, but the Commission should recognize the effect of those cost savings if the merger is approved. Thus, the full $550 million cost savings should be used as an offset against any legitimate stranded costs, if the Commission finds that Duquesne has any such costs in this case.

VI. REGULATORY ASSETS AND TRANSITION COSTS

Q. Is there a preliminary matter that you would like to discuss that concerns Duquesne's requests to recover regulatory assets and transition costs through a CTC?

A. Yes. Regardless of whether any of the amounts that Duquesne claims as regulatory assets or transition costs otherwise would qualify for recovery under the Act, it needs

to be recognized that none of those amounts are "stranded,"and thus recoverable through a CTC, unless future market revenues for Duquesne's sales of power are less than Duquesne's legitimate costs. But Duquesne has failed to demonstrate that it has any stranded costs and therefore, has no basis to support the imposition of a CTC in the first place. Therefore, whether the regulatory assets and transition costs claimed by Duquesne actually qualify as such is an academic question.

A. Regulatory Assets

Q. What are the dimensions of costs claimed by Duquesne as "regulatory assets"?

A. Duquesne claimed it had over $600 million in regulatory assets; *see* Statement No. 4, p. 7:10 - p. 8:5. Subsequently, these figures were updated and revised. *See* Exh. RBW-33.

Q. How did Duquesne go about analyzing amounts which it claims constitute regulatory assets?

A. Duquesne states that a regulatory asset is created when a company is permitted by accounting rules (particularly SFAS 71) to book an asset for a sum to be collected in the future for which the relevant regulator has issued a valid order which provides for the certainty of recovery of that sum. O'Brien, Statement No. 4, p. 5:1-8.

Q. What is your assessment of Duquesne's claims concerning the items and amounts claimed as regulatory assets?

A. Duquesne has overstated its regulatory assets in a number of ways. First, it has attempted to include as regulatory assets certain costs that never have been justified to the Commission. Second, it attempted to accelerate recovery of regulatory assets that are more correctly recovered at the time that generating units are either retired or sold. Third, it has used an unreasonable approach to functionalization of its regulatory assets to the generation function. There are numerous specific problems associated with many of the cost items.

Q. Does your testimony address all of Duquesne's proposed regulatory assets?

A. No. Many claimed items involve relatively small amounts, and in the interest of economy, I have focused on some of the larger issues. This focus should not be presumed to suggest that any of the claimed regulatory asset items is legitimate.

Q. Please describe your approach for reviewing items identified by Duquesne as regulatory assets or liabilities.

A. I reviewed the items with three primary goals in mind. First, I attempted to determine the extent to which each item is related to Duquesne's generation function. In contrast to generation, Duquesne's transmission and distribution functions will remain regulated after the year 2005, and the recovery of regulatory assets related to those functions is not impaired by the 1996 Pennsylvania legislation.

A corollary to the requirement that these costs be generation-related is that the costs must actually be stranded as a result of restructuring of the *generation* segment of the industry (e.g., that they cannot be recovered through transmission or distribution rates, or for that matter, from market-based revenues for generation service). Such a requirement is obvious: if a regulatory asset or other liability is not stranded as a result of electric industry restructuring, then there is no need to include it in Duquesne's stranded costs for recovery through the CTC.

Additionally, I attempted to determine whether the Commission has approved cost recovery associated with each item claimed by Duquesne as a regulatory asset. As noted by witness O'Brien (Statement No. 4, p. 5) if a regulatory asset has been created as the result of explicit Commission action, then it may qualify as a stranded cost. Conversely, if Duquesne has decided to defer recovery of costs, without sufficient Commission authorization, then that decision is the responsibility of utility management and does not qualify as a regulatory asset to be recovered as a stranded cost.

Q. Why should these items be scrutinized?

A. Duquesne has not had a decision in a General Rate Case since 1986. As a result, the prudence of many of Duquesne's expenditures has not been subjected to formal scrutiny by the Commission. Instead, Duquesne has made operating decisions, investments, other expenditures and deferred recovery of costs based on its own

management's judgement. Duquesne had the opportunity to go to the Commission for formal approval of the reasonableness of its actions but it decided to forego that option.

Consequently, Duquesne elected for a decade not to file to adjust base rates through the Commission's normal procedures. Therefore, it is essential to carefully screen Duquesne's claimed regulatory assets.

Q. What are the results of your analysis?

A. Applying these criteria, it is clear that Duquesne has dramatically overstated its stranded costs associated with these items. In fact, it now is attempting to recover the capital cost of items previously removed from rate base. Based on my assessment, and subject to any net stranded benefit that may be associated with Duquesne's generating assets, I have identified approximately $430 million in claimed rate base items that should *not* be recovered through a CTC. In contrast, Duquesne Witness O'Brien identified more than $483 million of rate base items for recovery as regulatory assets. *See* Exh. RBW-34. My proposed disallowances include:

TABLE VII-1
UNSUBSTANTIATED/DISQUALIFIED
RATE BASE ITEMS

Deferred Income Tax	$305,000,000
Cold Reserved Units	106,800,000
Deferred Coal Costs	12,191,000
Deferred Caretaker Expenses	6,772,000

Q. Is that the extent of Duquesne's claimed regulatory assets?

A. No. Described below is more than $125 million in additional items that Duquesne has claimed are entitled to regulatory asset status which have not been shown to qualify as regulatory assets.

TABLE VII-2
ADDITIONAL UNSUBSTANTIATED/DISQUALIFIED
REGULATORY ASSETS

Deferred Rate Synchronization	$41,450,000
Deferred Rate Synchronization Costs	270,000
Injuries & Damages	9,846,000
Warwick Mine	15,295,000
FAS 106 Costs	23,491,000
Compensated Absences	7,954,000
Transition Implementation Costs	11,000,000
Pilot Program Incentive Credit	14,150,000
Customer Education	2,000,000
Transition Filing	1,000,000

Q. Please explain how you reached that conclusion?

A. First I will review the three yardsticks that I used to determine whether an item qualified for stranded cost recovery. Then my testimony focuses on a number of particularly meritless regulatory asset claims made by Duquesne.

B. Valid Regulatory Order

Q. Has Duquesne met the basic threshold test of at least citing a valid regulatory order for each of its proposed regulatory assets?

A. No. Duquesne cited potentially valid orders for only 15 out of 25 categories of items, which represent approximately less than 60% of the total regulatory asset claims.

Q. Why do you say potentially valid orders?

A. For example, Duquesne claims that PUC Order R-870222 constitutes a valid order for recovery of $41.4 million of Deferred Rate Synchronization Cost, but as demonstrated below, that claim is incorrect.

Q. As another example of a potentially valid order, how many regulatory assets did Duquesne attempt to justify by reference to the PUC's order in R-870651?

A. Duquesne attempts to justify nine items, with an aggregate value exceeding $100 million, as regulatory assets by citation to the PUC's order in R-870651. *See* Statement No. 4, p.7:13-35.

Q. Is there a reason to be skeptical that deferred recovery undertaken for such items was the result of the Commission's directives?

A. Yes. The R-870651 order noted that Duquesne had proposed " 'the Duquesne Plan,' consisting of austerity measures, imposed by itself . . . . The self-imposed austerity includes . . . operating budget restrictions and a $58 million cap on the presently requested rate increase . . . ." The PUC welcomed "some of the Company's initiatives . . . ," although disclaiming responsibility "[i]f [the Company] suffers from negative consequences of risks which it assumed . . . ." Exh. RBW-35. Thus, at least some of the deferral of revenues resulted from the Company's own choice rather than because of administrative fiat.

C. Only Generation Related Regulatory Assets Should Be Recovered In the CTC

Q. Should only generation-related assets be incorporated into the CTC as regulatory assets?

A. Yes. Indeed, both Clayton and O'Brien testify that their proposal only includes generation-related regulatory assets. *See e.g.,* Statement No. 2 at p. 36 and Statement No. 4 at p. 7.

D. Duquesne Makes Invalid Claims of Regulatory Asset Status for Numerous Items

Q. Which regulatory asset claims of Duquesne will you analyze in this portion of your testimony?

A. Reviewed below are amounts attributed to deferred rate synchronization, deferred coal costs, Warwick Mine costs, Phillips and Brunot Island costs, unamortized debt and unamortized premium on reacquired debt, deferred taxes, injuries and damages, FASB No. 106, and compensated absences.

1. Deferred Rate Synchronization Costs

Q. Please describe Duquesne's claim with respect to $41.5 million in deferred Rate Synchronization Costs.

A. According to Witness O'Brien, Duquesne petitioned the Commission to defer initial operating and other costs of the Beaver Valley Unit 2 and Perry Unit 1 from November 1987. Statement No. 4 at p. 10:16-22.

Mr. O'Brien cites the November 1987 Order in Docket No. R-870222, for the claim that Duquesne was allowed to "seek recovery, over time" of the costs. Statement No. 4 p. 10:16-22.

Q. Did the November 1987 Order authorize recovery of the deferred costs?

A. Just the contrary. The order expressly declines to approve rate recovery of the costs (p. 2), declines to pass upon the costs' prudence or whether the units at issue were used and useful (*id.* and p. 6), declines to adjudicate the justness and reasonableness of the expenditures (p. 6), and specifies that

> this Order is not to be construed as a determination by the Commission . . . that Duquesne . . . may recover any of the deferred costs . . . . Exh. RBW-36.

Q. Did the Commission thereafter authorize Duquesne to recover these costs through rates?

A. No. According to Duquesne itself, the "Company deferred the costs . . . until March 1988, when a rate order was issued. In its rate order the PUC postponed ruling on whether these costs would be recoverable from the Company's utility customers. [As a result the] Company is not earning a return on the deferred costs." Exh. RBW-37.

Subsequently, in the Ft. Martin proceedings, Duquesne advanced a proposal regarding that status of the deferred costs. OCA objected to Duquesne's first proposal with respect to the deferred costs. As a consequence of OCA's objection, Duquesne amended its initial proposal. The amendment specifically recognized that OCA had not agreed "that an annual amortization of the . . . costs is recoverable in rates in Duquesne's next base rate proceeding." *See* Exh. RBW-38.

Q. What is your conclusion regarding Duquesne's right to guaranteed recovery of these costs through CTC?

A. The Commission has never authorized recovery of these costs -- in fact it has declined to authorize recovery not once, but twice.

2. Deferred Coal Costs

Q. Please describe Duquesne's claim for regulatory asset status of deferred coal costs totaling more than $12 million.

A. Prior to restructuring, the Commission imposed a cap on Duquesne's ability to recover in its current rates the cost of coal. Now Duquesne effectively seeks to bypass the effects of the coal cost cap.

Q. Outside of this proceeding, what is Duquesne's understanding of its opportunity to recover the deferred coal costs?

A. According to Duquesne,

> the PUC has established two market price coal cost standards for Duquesne. One applies only to coal delivered at the . . . Mansfield Station. The other, the system-wide coal cost standard, applies to coal delivered to the remainder of Duquesne's system. The PUC has directed Duquesne to defer recovery of the delivered cost of coal to the extent that such cost exceeds generally prevailing market prices for similar coal, as determined by the PUC. The PUC allows deferred amounts to be recovered from customers *when the delivered costs of coal fall below such PUC-determined prevailing market prices* . . . . Duquesne has exercised options to extend the coal cost standard through March 2000.

Exh. RBW-39 (emphasis added).

Q. Why is the contingent nature of Duquesne's ability to recover these costs important?

A. Only when (and if) the cost of coal for its plants was below this coal cost cap would Duquesne be able to recover deferred coal costs.

Q. Was Duquesne guaranteed that it would be allowed to recover these costs in the future?

A. No. Duquesne's own description of the arrangement (quoted above) demonstrates its understanding that it was only given the opportunity to recover these costs if and when its future coal costs were less then the "generally prevailing market prices for similar coal." However, there was no assurance that Duquesne's aggregate coal costs would be sufficiently low as to permit collection of the deferred amounts. Consequently, the deferred coal costs did not become stranded because of electric restructuring; their recovery had become highly contingent long before restructuring.

Q. Was the coal cost cap extended unilaterally over Duquesne's objection?

A. No. As the Company's Form 10-K acknowledges, Duquesne exercised its option to extend the cost cap into the future. *See* RBW-39.

Q. What is your recommendation regarding Duquesne's deferred coal costs?

A. Because Duquesne admits in its reports to investors that its opportunity to charge customers these amounts was contingent upon fuel prices and the like, the deferred coal costs should not be included in CTC. Should Duquesne divest generating assets and associated fuel contracts either as part of power plant divestiture or separately, it may maximize value from this transaction. If Duquesne's coal contracts will always be above market, the shareholders should absorb the consequences, which would have been the result under the coal cost cap. If Duquesne's coal contract prices fall below market (or if the acquirer of the contracts can achieve this outcome), Duquesne's shareholders will recover the deferred coal cost balance. In no event should responsibility for the coal costs fall upon Duquesne's customers.

3. Warwick Mine Cost

Q. Please briefly describe the Warwick Mine investment claim made by Duquesne totaling $15 million (Statement No. 4, p. 7:29).

A. Warwick Mine is wholly owned by Duquesne, and was operated in 1995-96 by a contractor. However, the Warwick Mine's contract operator notified Duquesne in 1996 that the operator was ceasing operations because of financial and geological conditions. Exh. RBW-39. The $15 million claimed by Duquesne represents the net book value of Duquesne's investment in the mine. The Company is seeking direct recovery of its capital investment in the mine from ratepayers.

Q. Has the Commission had anything to say about whether ratepayers should directly bear the capital costs of the Warwick Mine regardless of how the mine performs?

A. "On February 21, 1981, the . . . PUC . . . ruled that the Company's Warwick Mine should be taken out of rate base . . . ." according to Duquesne's then - President and Chairman of the Board. Instead, *if* the Warwick Mine was efficient enough to produce coal at a cost below the average price of comparable coal, Duquesne was permitted to earn a reasonable return *on* its investment. Exh. RBW-40.

Q. Can you provide additional detail regarding how Duquesne was to be compensated for Warwick Mine production?

A. Subsequent to 1981, the Company was permitted to recover its investment *through the cost of coal* subject to the coal cost cap (in the ECR) that also applied to deferred coal costs, as described above. Nonetheless, as Duquesne acknowledged in 1995, the "Warwick Mine has been excluded from rate base since 1981." Exh. No. RBW-41.

Q. Does this treatment entitle the Warwick Mine capital investment to regulatory asset status?

A. No. It is disqualified for the same reason that applies to deferred coal costs -- recovery of costs was not assured, but could occur only when conditions demonstrated that the public interest was served (*i.e.*, when the costs fell within the ECR charge). In fact, Duquesne's effort to directly recover the capital cost of the Warwick Mine from ratepayers, rather than through the cost of coal when that cost

was low enough to benefit ratepayers, is even more objectionable than Duquesne's proposal on deferred coal costs. This claim is particularly striking because the operation of the mine has collapsed and yet Duquesne returns to the Commission -- which previously had rejected rate base treatment for Warwick -- for a bailout.

Q. Has the Company exhausted the options available to mitigate the costs of the Warwick Mine?

A. No. Of course, as a mine, it might be operated as a real estate investment trust or a master limited partnership, with consequent savings and increased value, but Duquesne makes no mention of that opportunity for the Warwick mine. Warwick Mine should be divested either as part of the divestiture of Duquesne's power plants or through a separate auction of any generation related fuel assets. Any gain could then be credited towards Duquesne's stranded costs, after adjustment by an appropriate incentive mechanism to encourage Duquesne to maximize the revenue resulting from this asset sale. But in no event does Duquesne's failed investment qualify as a regulatory asset.

4. Phillips and Brunot Island Costs

Q. What is the history behind the rate treatment of the costs of the Phillips Station and a portion of the Brunot Island facilities?

A. In 1986 the PUC approved the Company's request to remove Phillips and a portion of Brunot Island from rate base. As a result, these facilities were excluded from rate base for a decade.

Q. If the facilities were taken out of rate base, why does Duquesne maintain that the costs associated with the facilities should be recovered from ratepayers?

A. In 1996 – the same year as the Pennsylvania Act was enacted -- the cost of the cold reserved Brunot units was again placed in an account used for electric plant in service. Exh. RBW-42.

Q. What are Duquesne's plans for returning the cold reserved Phillips and Brunot Island units to utility service?

A. It has none. Exh. RBW-43.

Q. Are you saying that Duquesne plans to do nothing with these assets?

A. Duquesne *does* plan to exploit the value of these assets, by building new generation capacity on these sites.

Q. What facilities has Duquesne considered for Brunot Island?

A. According to the Company's IRP filed in September, 1997, Duquesne expects to restore to commercial operation Brunot CT units, *inter alia*, "to support . . . long-term off-system sales," presumably at deregulated rates, after the year 2000, and to reactivate a CC facility in 2007, after the transition period contemplated by the Act. Exhibit RBW-44.

Q. Please describe the costs associated with the Phillips and Brunot Island facilities that Duquesne seeks to recover from ratepayers.

A. There are two sets of costs. One set is associated with the "care and feeding" of the Phillips and Brunot Island facilities that have been shuttered for a decade while Duquesne strategized on how it could attempt to recover some value from the facilities. These costs, amounting to $6.77 million, are "caretaker" costs.

Q. Are the caretaker costs for Phillips and Brunot Island reasonable?

A. No. Duquesne has retained these assets since they were put into cold reserve in 1986 and in so doing has retained its options. This "option" was purchased based on Duquesne's management decision. Duquesne did not need to retain these sites if it truly believes its own testimony here, namely that low-cost power is available in ECAR. Thus, the cost of retaining this option should rightfully fall on Duquesne's shareholders.

Q. What order has Duquesne cited as support for recovery of the deferred caretaker costs?

A. The Company cited Docket No. P-900485, in which Duquesne and GPU proposed construction of a new transmission line to GPU service territory, the sale by Duquesne of the Phillips Station, and related transactions.

Q. When was the transmission line built and the Phillips Station sold by Duquesne?

A. The transactions were never consummated and the benefits envisioned as flowing from those transactions never materialized. Some of the benefits envisioned to flow from transaction were embodied in a settlement, which the Commission reviewed in P-900485. In its review, the Commission noted that "[i]f the Transaction cannot go forward, the Settlement is moot because no regulatory treatment of costs and revenues will occur." RBW-45.

Q. Does the P-900485 order cited by Duquesne as authorizing the recovery of the stranded costs here at issue make any statements about its subsequent effect?

A. The Commission noted that contained within its power to approve petitions was "the power to restrict our approval" in a way that preserves the rights of parties to contest issues which might arise in other proceedings before the Commission. P-900485 (Part II.B2.g). The Commission noted that "the Settlement does not pre-approve future actions to be taken by Duquesne." *Id.* at 40.

Q. Is there subsequent information that undermines Duquesne's claim that Brunot Island and Phillips costs qualify as regulatory assets?

A. Yes. Duquesne this year expressly recognized that"[i]n the event that market demand, transmission access or rate recovery do not support utilization of these plants, the Company may have to write-off part or all of these investments and associated costs." Exh. RBW-39. Even the Company recognizes that lack of transmission access is one factor that prevented recovery of the costs. Moreover, by admitting that the costs may be written-off, the Company acknowledges there is no certainty as to the costs' recovery.

Q. What costs, aside from the caretaker costs, are associated with Brunot Island and Phillips for which Duquesne seeks recovery?

A. The underlying capital investments.

Q. How much does Duquesne claim for the facilities?

A. It claims stranded costs of $106,800,000 for the Brunot Island and Phillips facilities. See Statement No. 4, p. 15, 12-14.

Q. Is Duquesne interested in selling these facilities?

A. Yes. Duquesne hopes to investigate sale of the facilities between now and the scheduled dismantling of the Brunot Island units in 2013. Exh. RBW-46.

Q. What valuations of the facilities have been provided to Duquesne?

A. Recall (from Part III.A.) that one of Duquesne's consultants valued Brunot Island as high as $112 million and Phillips as high as $140 million. *See* Exh. RBW-7.

Q. What is your recommendation regarding the costs associated with the Phillips and Brunot Island facilities?

A. Duquesne is not entitled to stranded cost treatment for any amounts associated with these facilities. Duquesne may attempt to divest these assets. Any premium above book value for these two facilities could at least partially be allocated to pay the caretaker costs, and offset stranded costs (if any) of other facilities.

Q. Have others identified these items as questionable?

A. Yes. The PUC's Audit Staff noted that the Company's Form 10-K admitted that Duquesne may have to write-off part or all of the cold-reserved units, as quoted above. According to the Staff, Duquesne has not indicated a time when it expects to start using the property for utility service. *See* Exh. RBW-26. Indeed, as noted above, the Company admitted in this proceeding that it has no plan to return the cold reserved units to utility service. The PUC's Staff further observed that the Uniform System of Account instructions for plant held for future use require that property so classified be subject to a definite plan for future use.

Q. What is the appropriate action in light of those facts?

A. As the PUC's accounting Staff suggested, the facilities should be removed from rate base, their costs classified into Account 121, non-utility property, and no amounts associated with Brunot Island and Phillips cold reserved units should be recovered from ratepayers.

Q. Have adjustments to plant balances associated with these facilities been recommended?

A. Yes. The PUC's accounting staff sampled Duquesne accounting records and found that almost $1.3 million that Duquesne had claimed as electric plant in service at Brunot Island should be transferred to a non-utility property account. *See* RBW-26. Any Duquesne stranded cost claim should be modified to comport with the results of the accounting staff's examination of Duquesne's books.

5. Deferred Taxes

Q. Please describe Duquesne's proposed regulatory asset associated with deferred taxes.

A. Witness O'Brien has testified that the PUC policy of including in rates only "actual taxes paid," except where Federal law requires normalization of tax benefits, *see* Statement No. 4 p. 8, has resulted in a Deferred Taxes regulatory asset with an initial balance of $550 million in 1994 and a claim of $304.94 million for recovery in this proceeding. *See* Exh. DJC-4 p.1.

Q. Please explain your concerns regarding this claimed regulatory asset.

A. First, Duquesne made additional capital investments in generation facilities during the years following its last case determining base rates ten years ago. These additions in turn contributed to deferred income tax balances. The deferred income tax consequences of these capital additions, which have not been reviewed or approved in a general rate case, should not be presumed to qualify as regulatory assets.

Q. Is there an additional deficiency with Duquesne's proposal to treat deferred taxes as regulatory assets to be recovered in the CTC?

A. Yes. Duquesne insists that it should earn a return on the deferred tax balance. *See* Statement No. 4, p. 7:1-9.

Q. What is the problem with that request?

A. Typically, deferred tax balances are not permitted to earn a return on equity. Duquesne in this case is requesting, by means of the CTC, receipt of revenues for tax bills that may not have to be paid for years into the future. In effect, the CTC provides Duquesne with funds, before the obligation must be paid. Imposing a return on the deferred tax balance would be contrary to traditional regulatory practice and unwarranted.

6. Unamortized Debt Costs and Unamortized Premium on Reacquired Debt

Q. Please describe Duquesne's rationale for recovery of the unamortized debt costs and premium on reacquired debt in its CTC.

A. Duquesne indicates that these costs historically have been amortized over a period of time, rather than recovered at the time that debt was either reacquired or issued. *See* Duquesne Statement No. 4, page 9.

Q. Has Duquesne demonstrated that these costs were incurred as a result of electric industry restructuring in Pennsylvania?

A. No. Witness O'Brien makes no such claim. However, he does indicate that, in his opinion,"[d]ue to the restructuring . . ., the Company will not be able to recover fully the unamortized (sic) remainder of the expense." *See* Duquesne Statement No. 4, page 10. Notably, he does not contend that *none* of the balance will be recoverable in the new market for power supplies. Nonetheless, it appears that Duquesne has claimed as a regulatory asset the *entire* amount of this item that Duquesne attributes to the generation function.

Q. What is the existing amortization schedule for the cost of reacquired debt?

A. Duquesne indicates that it will amortize these premiums over the life of the debt. *See*, Exhibit RBW-47.

Q. What amortization schedule for the cost of reacquired debt has Duquesne proposed in this proceeding?

A. It proposes to recover the entire reacquisition premium during the transition period. *See* Statement No. 4, p. 9:19-10:15.

Q. Is Duquesne's proposal reasonable?

A. No. Since the regulatory asset portion of these costs was incurred in order to finance the construction and/or purchase of generating assets, the reacquisition premium and issuance cost should be amortized consistent with Commission policy, which means that it should be amortized over the remaining life of the debt. Duquesne's generating assets will not disappear in their entirety at the end of the transition period; operating units (and Duquesne shareholders) will continue to benefit from the lower debt costs obtained by refinancing in future years. Traditional regulatory policy focuses on matching the cost of a benefit with the benefit itself, but Duquesne's proposal ignores that principle by making ratepayers responsible for all of the post-2001 cost of this item while conferring the post-2001 benefit upon Duquesne shareholders.

Q. What is your recommendation for the amortization of this regulatory asset if Duquesne should divest its generating assets?

A. Presuming that the transaction is a taxable event to Duquesne, any remaining portion of this regulatory asset should be paid down.

Q. How should this regulatory asset be recovered if Duquesne's generating assets retire prior to full recovery?

A. That case should be handled similarly to the asset sale case. The remaining balance of the regulatory asset should be recovered at that time through a one-time charge.

7. Injuries and Damages

Q. Please describe Duquesne's alleged regulatory asset for Injuries and Damages.

A. Witness O'Brien claims that "[t]hese costs relate to the Company's workers (sic) compensation liability". *See* Duquesne Statement No. 4, page 11.

Q. What is Duquesne's rationale for inclusion of these regulatory assets in its CTC?

A. Duquesne indicates that this regulatory asset results from a difference in timing between when the liability is booked and when amounts are actually recovered through rates.

Q. When was the last time that the magnitude of this regulatory asset could have been assessed by the Commission?

A. Duquesne's last rate case, Docket R-870651. Thus, there is no certainty that the costs now associated with this regulatory asset are just and reasonable.

Q. Do Duquesne and HSS/ARI agree that at most only generation-related "Injuries and Damages" costs should be included in the CTC?

A. Apparently. Witness O'Brien testified that "If the Company's generation had remained part of the regulated assets, Duquesne would recover the difference . . . over time. Because the generation portion is being deregulated, however, Duquesne will not be permitted to recover these amounts." (See Statement No. 4, p. 11).

Q. What do you recommend regarding inclusion of this particular regulatory asset in CTC?

A. No. None of the expense has been shown to be generation-related.

8. FAS No. 106 Costs

Q. Please describe Duquesne's obligations associated with FAS No. 106.

A. Duquesne states:

> FAS No. 106 was issued in December, 1990 and became effective for Duquesne beginning in 1993. This statement required the accrual established for these types of post-retirement benefits. Consistent with the Commission's guidelines for implementing FAS No. 106, the Company is amortizing the liability required upon adoption of this statement over 20 years. Due to the change in legislation, this liability which related solely to employees [sic] liability incurred prior to the date of legislation must be now recovered over the transition period of the Act rather than the original 20 year period. [*See* Statement No. 4, pp. 13-14.]

Q. Should only generation-related FASB 106 costs be included in the CTC?

A. Yes. As discussed above, Duquesne apparently agrees that only generation-related FASB 106 costs should be included in the CTC. Moreover, any generation-related

FASB 106 costs should be funded by the divestiture of the generation assets. Obviously, to the extent that the divestiture proceeds are essentially pre-funding payment of this liability, this funding should be treated in the same manner as nuclear decommissioning funds, rather than as an interest free loan from the ratepayers.

Q. Are these costs that Duquesne's potential competitors in the deregulated market will face?

A. Yes. FAS No. 106 applies to other power merchants, not just Duquesne.

Q. Would recovery of these costs through a CTC give Duquesne an unfair advantage in the deregulated electric generation market in which Duquesne will likely participate?

A. Yes. Allowing Duquesne to recover these costs outside of the deregulated generation market would clearly give Duquesne a competitive advantage over other firms that have to recover these costs on a going-forward basis. In certain hours, it will allow Duquesne to recover these costs twice: once through the CTC and once through the generation market. Thus, the costs do not qualify for recovery in the CTC because there has been no showing that the costs will not be recovered in the competitive market.

Q. What is your recommendation regarding the FAS No. 106 costs?

A. I recommend that Duquesne not be given an unfair advantage over other competitors. As a result, the Commission should not include any of Duquesne's FAS No. 106 costs attributable to the period after the transition in the CTC.

9. Compensated Absences

Q. Please describe how compensated absences, for which Duquesne claims $8 million in regulatory assets, arise.

A. The Company accrues amounts to recognize employees' claims to future paid absences from work.

Q. Why have you questioned that item?

A. Duquesne has eliminated hundreds of employees over the past decade, and likely will eliminate an additional significant number of employees in the future either as the result of competition, the merger with APS, or both. Some of these reductions will be through voluntary buyouts and other employment terminations in which the employee does not obtain the full value of the accrued amounts. Given the fact that no scenario points to higher, or even *status quo*, employment headcounts at Duquesne, at a minimum the Company is obligated to demonstrate that its accruals will not result in a windfall as the Company reduces its headcount. Additionally there has been no showing of the actual proportion of these costs that is related to generations.

E. Transition Costs

Q. Does Duquesne claim to have any "transition costs?"

A. Yes. Duquesne identifies five categories of such expenditures. Duquesne, Exhibit DJC-5. They are:

(i) expenses related to Duquesne's pilot program implementation;

(ii) expenses related to customer education;

(iii) restructuring filing expenses;

(iv) restructuring implementation expenses; and

(v) deferred pilot program costs.

Duquesne is claiming, in total, $18.2 million associated with those items. *See* Exhibit DJC-5.

Q. Does Duquesne explain why, in its view, those expenses qualify as "transition costs" that can be recovered through a CTC?

A. No. Duquesne's witness Clayton identifies the costs but does not explain either why, in his view, they qualify as "transition costs" or why Duquesne should be permitted to recover them through a CTC.

Q. Do you believe that Duquesne should recover its expenses associated with those items as "transition costs?"

A. No.

Q. What is your reason for concluding that Duquesne should not recover the expenditures as "transition costs?"

A. I disagree with Duquesne's characterization of the items as "transition costs" because the items are not the types of costs that the Act describes as "transition costs." Section 2803 of the Act describes the term "transition costs" as including costs of a utility related to employee severance, retraining, early retirement, out placement and related expenses for employees who are affected by changes that are occasioned by the Act. Thus, in referring to the definition of transition costs in Section 2803 of the Act, I did not see language that would support Duquesne's request that pilot program expenses, restructuring related expenses or expenses of consumer education should be treated as transition costs. Further, Duquesne did not reference any other section of the Act as support for its request to recover those expenses as stranded costs. Therefore, Duquesne has not provided an explanation that shows that it is entitled under the statute to recover any of the costs of those items through a CTC.

VII. DUQUESNE CREATED ARTIFICIALLY DEPRESSED ESTIMATES OF MARKET CLEARING PRICES

Q. Dr. Weisenmiller, please summarize your analysis of Duquesne's estimation of post-2005 market prices for electric power, and the effect of Duquesne's estimates on its stranded cost claim.

A. Duquesne calculated its January 1, 2006 claimed stranded cost based upon the difference between its projected net book investment in generation and regulatory

assets and a forecast of the market value of generation from its generating plants. Thus, by inflating Duquesne's projected net book investment and deflating forecasts of future market prices, Duquesne would maximize its stranded cost claim. In prior sections of this testimony, I have shown that Duquesne's projection of its net book investment is unreasonably high. Duquesne also used unreasonable assumptions to deflate its predictions of future market prices to unreasonably low levels, ultimately overstating stranded costs.

Q. Please summarize Duquesne's approach towards estimating the value of power.

A. Duquesne retained Michael M. Schnitzer to determine stranded costs. Mr. Schnitzer used "the difference between net book value and competitive market value" to establish the "portion of book value stranded by competitive retail access. The key quantification issue concerns the market value of generation." (See Schnitzer, Statement 3, p. 7). Mr. Schnitzer supported the use of an annual dump wholesale of power to establish this market value, rather than an administrative determination of market prices today based upon a computer simulation model such as the GE MAPS approach used by witness Howard Pifer on behalf of West Penn in its restructuring proceeding. (*See* West Penn, Statement 6). However, Mr. Schnitzer also developed an "upper bound range" of ceiling market prices in 2006 "based on the cost of entry by new construction *assuming* that such entry is in fact economic in 2006." (Statement 3, p. 25; emphasis in original)

Q. Why does Mr. Schnitzer support setting the market price of power using an annual solicitation rather than an administrative determination?

A. Administrative determinations require forecasts that are "... highly sensitive to the initial assumptions chosen by the analysts making the forecasts." (Statement 3, p. 9). Witness Schnitzer also identifies three sets of assumptions that are critical:

1. The choice of new supply technology;
2. A "need date" for new technology; and
3. Fuel prices. *Id.* at p. 8:1-19.

He states that historically assumptions for these forecasts invariably have been wrong and that the resulting "market price projections have been overstated significantly." He also states that administrative determinations of market prices lead to a "battle of experts" that is a "contentious and time-consuming process." *See* Statement 3, pp. 8-9.

Q. Dr. Weisenmiller, would you comment on Mr. Schnitzer's testimony?

A. I would prefer an asset sale to value Duquesne's generation assets, rather than an administrative determination of stranded costs. As discussed in Section III.C., Duquesne's use of incremental wholesale dump sales is flawed and understates the value of power. Accordingly, I would propose that Duquesne divest its generating assets and let the market determine their value. Indeed, Duquesne has already

established, through its sale of Ft. Martin and its merger with APS, the value of its generating assets.

Second, I agree with Mr. Schnitzer that an administrative determination of stranded costs can lead to a complex proceeding that is essentially "the battle of the experts" and "the battle of the models." But Mr. Schnitzer neglects to point out that Duquesne's case rests not only on the wholesale dump sales results but also upon computer models: Mr. Clayton's modeling of the net present value of the generating plant assets in 2005 is based upon computer generated forecasts of their cost components between 1996 and 2026 (*see* Statement No. 2, Exh. DJC-3), and Mr. Schnitzer's derivation of a new entrant ceiling price range in 2006 (Statement No. 3, Exh. MMS-2, 3, 4, and 5) also is based on a model. Thus, Duquesne's approach does not eliminate the need for evidentiary hearings on computer models and their assumptions. Divestiture would diminish or eliminate the role of administrative hearings not only with respect to the value of power, but also the costs and values of West Penn's generating assets and the ceiling price established by new entrants.

Finally, I agree that Mr. Schnitzer has identified variables that have critical impacts upon determination of the future value of power (although his list may not be exhaustive).

Q. Before discussing the specific assumptions, what is your reaction to Mr. Schnitzer's claim (at pp. 8:17-18) that these types of forecasts invariably are too high?

A. The world is not that simple, as demonstrated by a review of assumptions identified by Mr. Schnitzer as critical. For instance, consider the new supply technology of choice. He asserts that "costs and thus prices are usually projected assuming that technology never improves, costs never decline and efficiency gains are never realized." (Statement No.3, p.8.) Unfortunately, the last twenty to thirty years also offer a number of counter-balancing examples of overly optimistic projections. For example, nuclear power was once expected to be "too cheap to meter," but the projected installed costs for nuclear units in the seventies were off by an order of magnitude. Technology improvements have emerged at a much slower pace than hoped for synthetic fuels plants, "breeder" reactors, fusion technology, fluidized bed technology, photovoltaic, wind conversion devices, etc. Demand side management technology also has turned out not to be as inexpensive as predicted by some forecasts. In fact, improvements in turbine technology in the past decade have been one of the few technology surprises. However, it is equally dangerous to extrapolate such improvements indefinitely. Indeed, some of the advanced turbines currently in use have suffered operational problems. *See* for example the Doswell experience and the host of problems identified with the latest generations of turbines.

Q. Are there any other factors not considered in Mr. Schnitzer's optimistic assessment?

A. Yes. First, air emissions requirements have grown increasingly stringent for new facilities for at least the past ten years. Concerns over "greenhouse gases," "acid rain," and other issues that might emerge in the next ten to twenty years could lead to substantially enhanced emissions control requirements, which could increase the costs or degrade the performance of new fossil-fired power plants. This is a particularly significant issue in light of Duquesne's inconsistent treatment of clean air costs for gas and coal facilities, discussed below. Second, restructuring has slowed the installation of new generating capacity in the United States. There is essentially an "over-hang" of potential turbine construction capability, which results in fairly aggressive vendor pricing at this time. However, if West Penn witness Pifer is correct, then 24,375 MWs of either CTs or CCs would be installed in ECAR, PJM, or SERC by 2005 and another 67,375 MWs of either CTs or CCs would follow by 2010. These demands just within the continental North American market could lead to increased prices for this equipment, even if it is the technology of choice.

Q. What about Mr. Schnitzer's concern that facilities could be built before they are needed and drive down market prices?

A. With a deregulated market, project proponents will absorb the risks of building uneconomic resources, which should result in resource additions occurring only when market prices demonstrate sufficiently high levels to support investment. In such an environment there will be periods of time where prices will be in excess of long-run replacement cost. Thus, construction of new resources will not cap

automatically the value of power, but a substantial number of resources will need to be added on a continuous basis before these resources act as an effective cap.

Q. What about Mr. Schnitzer's third concern that fuel price forecasts are invariably too high?

A. I will discuss this issue in detail below, but Mr. Schnitzer is essentially assuming that the recent past will be reflected throughout the next 30 years. Thirty years ago a number of analysts made the same type of mistake with oil and gas prices, producing forecasts that were too low.

A. Key Assumptions

Q. In addition to the foregoing analysis of Mr. Schnitzer's conceptual errors, have you identified particular assumptions Witness Schnitzer utilized for his computer simulations?

A. Yes. Some of the major problems with Duquesne's simulations include:

1. Characteristics of resource additions;
2. The gas price forecast;
3. The inflation rate forecast; and
4. Pollution control technology.

1. Overly Optimistic Characteristics of New Resource Additions

Q. Please describe Mr. Schnitzer's assumptions concerning resource additions.

A. Mr. Schnitzer has assumed that combined cycle units will be built to meet future load growth and to replace existing capacity, so they effectively will cap the market price of power. His assumptions regarding the cost and operational characteristics of these units are presented in Schnitzer, Statement No. 3, Exhibits MMS-2, MMS-3, MMS-5.

Q. How do these resource additions impact the forecast price of power?

A. Witness Schnitzer assumes that gas-fired combined cycles will be the technology of choice for new entrants and thus would establish the value of power beginning in 2006. *See* Statement No. 3, p. 26. In effect, he is assuming the operating costs of these resources will "cap" the value of power, because additional resources will be added whenever the value of power is above their costs.

Q. Does Schnitzer take into consideration locational effects on the cost of the projected CC units?

A. No. He assumes that all generic resource additions have the same cost and operating characteristics. In other words, he assumed that the cost of constructing, owning and operating a new CC unit is constant regardless of whether the unit is located in an area where land and fuel are relatively inexpensive (*e.g.*, the Midwest) or where land and fuel are relatively scarce (*e.g.*, the Northeast). *See* Statement No. 3, Exhibit MMS-3.

Q. Do you have any other specific concerns regarding Schnitzer's cost assumptions for these CC units?

A. Yes. First, Schnitzer assumed significant technological improvement in CC units. His optimism was discussed above. His assumptions of technological improvement can be contrasted with the assumptions of the EIA, Penelec, PECO, AYP in its evaluation of Ft. Martin, and even Duquesne in its most-recently filed Integrated Resource Plan, *see* Exhibit RBW-48. As can be seen from the exhibit, the heat rate Duquesne presumes here for the generic units is lower than that used by Penelec, EIA, or AYP.

Q. Can you provide the Commission with an estimate of the "all-in" costs of these competing plant specifications?

A. Yes. Because the overall cost of generation typically is a function of the amount the generator runs, I have performed a parametric study in which I changed only the capacity factor of the unit. *See* Exhibit RBW-48.

Q. What do you conclude regarding Witness Schnitzer's assumptions?

A. Duquesne's assumptions concerning CC operating costs are less than those of any other party, and even less than its estimate used in its Resource Plan. *See* Exhibit RBW-48.

Q. Please describe how you reached these conclusions?

A. I used fixed and variable costs for generic CC units obtained from a number of different sources: Penelec, PECO, EIA , AYP (in its evaluation of the Ft. Martin purchase) and the values provided by Witness Schnitzer. I then estimated the fixed costs, on a cents/kWh basis, at different capacity factors. By summing the variable costs and the fixed costs at different capacity factors, I estimated overall costs for these generic CCs.

Q. Of the various sets of presumed characteristics of CCs that you examined, which set had the lowest overall costs?

A. Witness Schnitzer had presumed by far the lowest overall costs ($32.3/MWh "DQE CC low" and $34.5/MWh "DQE CC high") for CC units. Witness Schnitzer's estimate remains the lowest, even after I adjusted for his assumptions regarding natural gas prices, which, as I will discuss below, are unreasonably low. Witness Schnitzer used a different fixed charge rate that we were unable to review because the formula was not provided. Also, changes in gas prices and inflation would change the relative weighting of fixed and variable costs in determining the overall cost of power from these units. Thus, the impacts of these overly optimistic generic unit assumptions are magnified by the similarly optimistic fuel and inflation forecasts.

2. Overly Optimistic Gas Price Projections

Q. Why are Duquesne's assumptions regarding natural gas prices important in determining future electric prices?

A. They are critical in determining what Duquesne characterizes as its ceiling for the market price of power in the post-transition period (beyond the year 2005) because natural gas is the primary fuel source for CC units, Mr. Schnitzer's assumed technology. Further, although Duquesne has relied solely on an 8-year RFP to determine the market line in the Transition Period, it is reasonable to consider alternative market lines that rely, at least in part, on natural gas prices in the transition period. Because future natural gas prices are so important, Duquesne should have adopted reasonable assumptions regarding future natural gas prices -- but it did not.

Q. What flaws exist in Duquesne's natural gas price forecast?

A. The flaws primarily are in two areas. First, Duquesne has chosen a wellhead gas price forecast that is low by any review of reasonable existing forecasts. Second, Duquesne also has used a gas transportation price that is unrealistically low.

Q. What did Duquesne use for a wellhead gas price forecast?

A. Duquesne witness Schnitzer obtained "quotes for forward prices through 2005 for gas delivered to Henry Hub in Louisiana." (Statement No.1, Schnitzer, p. 26).

Discovery revealed that these "quotes" consisted of a letter from an over-the-counter brokerage firm. Exhibit RBW-49. The forecast is basically flat in nominal terms, in the range of $2.20 to $2.60 per MMBtu. Because this projection is stated in nominal terms, it implies that real fuel prices *decrease* in each year at approximately the rate of inflation through 2026.

Q. Is this forecast reasonable?

A. No. I reviewed publicly available natural gas wellhead forecasts released by EIA, WEFA, DRI and GRI. Exhibit RBW-50. Any individual forecast should be treated with caution as they all have performed poorly in the past at predicting future prices. However, over the period 1995 to 2015, all of these forecasts predict real increases in the price of natural gas, ranging from 0.1 to 2.5%/year.

Q. How is it that the forward price quoted by the brokerage firm is lower?

A. Duquesne has not provided any information concerning how Merrill Lynch developed this price quote. Although Merrill Lynch apparently provided a then-current price quote that reflects its price expectation, it did not commit that it would contract to provide gas at that price starting in 2006 for 10 or 20 years.

Q. How does Duquesne incorporate the cost of natural gas transportation into its model?

A. It is introduced in Schnitzer's market line spreadsheets in the post-transition period. As noted earlier, Duquesne relies solely on the RFP to predict the market line in the

transition period. According to Schnitzer, he used a 4-year basis differential quote between Henry Hub and the TCO pool. (Statement No.1, Schnitzer, p. 27.) This differential is set at $0.20/MMBtu. (Exhibit MMS-3, p. 1)

Q. What is the basis of this gas transportation cost forecast?

A. In response to an interrogatory that asked for source documents and any alternative documents reviewed, the only support or justification provided by Mr. Schnitzer was contained in a single handwritten page. Whoever provided that estimate to Mr. Schnitzer noted that it was a "Best Guess Transport" rate. That person's "best guess" is the sole basis that Mr. Schnitzer relies upon for his differential of $0.20. Exhibit RBW-51.

Q. What inherently unreasonable presumptions about natural gas transportation rates did Duquesne make?

A. Witness Schnitzer's model severely over-simplifies natural gas market dynamics because it applies the same delivered gas cost to all potential generating units throughout the U.S., thus ignoring the reality that transportation costs for new resources likely will vary from region to region and therefore vary for different generating units, depending on location.

Q. Is Witness Schnitzer's best guess $.20 transport rate consistent with real world data?

A. No. I examined historical differentials between wellhead and Midwest citygate prices. I also examined the historical transportation rate reflected in delivered to electric utility prices from the EIA. I looked at actual data for the last four years. These differentials average in the $0.50 to $1.00/MMBtu range, or 2.5 to five times Witness Schnitzer's best guess transport rate.

Q. Do Schnitzer's assumptions regarding natural gas match what Duquesne forecasted less than a year ago?

A. No. In Duquesne's latest IRP plan, filed September 1996 and updated May 1997, Duquesne used a natural gas price escalation rate of 4.9%/year.

Q. Can you summarize your view with respect to the assumptions Duquesne used to forecast natural gas prices?

A. Duquesne's assumptions uniformly result in unreasonably low forecasts of natural gas prices. As a result, I believe that Duquesne's forecast of future electric prices is unreasonable and cannot be accepted as a basis upon which to calculate stranded costs. Thus, I recommend that Schnitzer's market line, including the gas forecast embodied in it, be discarded. If Schnitzer's market line methodology is to be used, however, I recommend that its gas price component be escalated at 1.0%/year in addition to escalation for the rate of inflation.

3. Overly Optimistic Inflation Assumptions

Q. Why are assumptions regarding inflation important?

A. Lower inflation rates mean that components of market-clearing prices rise more slowly, and hence market-clearing prices increase more gradually, than with a higher presumed inflation rate. All of the cost components of a *new* generation facility are exposed to the effects of inflation. Thus, the rate of inflation directly affects the entirety of such new capacity. In contrast, existing plants' costs include amounts which already were expended, are kept on the books at historical costs, and, thus, are not affected to the same degree by a change in future rates of inflation as are new facilities. As a result, lower inflation rates lead to lower costs for new facilities and reduce the resulting market-clearing prices from new facilities placed in operation to satisfy increased demand. The bottom line is that an unrealistically low projection of inflation can create an artificially depressed market-clearing price projection, in turn inflating stranded costs.

Q. What annual rate of inflation has Duquesne's Messrs. Schnitzer and Karl presumed to be in effect during the period in which transition costs are computed?

A. Mr. Schnitzer presumes that inflation will be 2.5%/yr. *See* Statement No. 1, Exhibits MMS 2, 3, and 4. Mr. Karl assumes a gross national product price deflator ("GNPPD") of 2.4%/yr to 2.7%/yr. *See* Volume IV, Exhibit MGK-4. Inflation figures are used to compute costs and determine the market price over the 28 years (1998-2026) subject to Duquesne's projections.

Q. What was the basis for Mr. Schnitzer's inflation forecast?

A. In response to a request for "all sources relied by Duquesne to justify its presumed 2.5% inflation factor," Duquesne's witness Schnitzer stated that he used a 2.5% inflation factor because Mr. Clayton used a 2.5% inflation factor. Exh. RBW-52. Thus, Mr. Schnitzer apparently made no independent evaluation to determine the propriety of a key assumption in his forecast. Witness Clayton's testimony does not provide any justification for the number.

Q. What has the average annual inflation rate been in the past?

A. The U.S. Department of Commerce has published almost seventy years of price deflator data. I was able to compare Duquesne's forecasts of inflation to the gross *domestic* product price deflator ("GDPPD"), which is closely related to the GNPPD and has become the more common measure of general inflation. The average level of the GDPPD during the last twenty five years (1972-1996) has been 4.64%/yr. During the last 50 years the average has been 4.2%/year. These historical measures of inflation exceed Duquesne's projection by more than 60%. *See* Exh. RBW-53.

Q. How many times during the last 50 years has the GDP price deflator increased on average at a rate of 2.5% or less annually for a twenty-five year period?

A. Never. Twenty five year averages in that period (e.g., from 1946-1970, 1960-1984, etc.) range from 4.1% per year to 4.6% per year. There is no twenty-five year period incorporating the Commerce Department data that features inflation that averages as

low as 2.5%/year, unless I incorporate the entire period of the Great Depression. As a result, Duquesne's presumed inflation rate appears highly improbable.

Q. Do you believe that Duquesne's projection of low inflation rates indefinitely into the future is credible?

A. No. Serious outbreaks of inflation occur periodically. During just the last half century, the U.S. experienced significant inflation in 1946-47 (11-12% increases in the annual GDPPD), 1951 (6.8%), 1974-75 (9-9.5%) and 1979-81 (8.5-9.4%).

Q. Why is Duquesne's forecasted inflation so out of line with actual experience reflected in the Commerce Department's data?

A. Forecasters may mistake the recent past as the predicate for the indefinite future. For instance, some forecasters during the 1980's estimated future inflation rates substantially in excess of levels that actually materialized, in part because inflation "spikes" had occurred in 1979-81. The last five years have featured declining inflation rates, and forecasters' expectations may have been colored by that short-term performance.

Q. What is Duquesne's own estimate of inflation for the period through 2001?

A. In Duquesne's July 1, 1996 IRP, it forecast inflation as follows:

Duquesne's Forecasted Inflation (%/yr)

	Base	Optimistic	Pessimistic
CPI	3.6	3.1	3.9

Source: Exhibit RBW-54.

Q. How does CPI compare with GNPPD or GDPPD?

A. CPI measures consumer goods and uses fixed weights, and has historically been higher than broader inflation indices such as the GNPPD or GDPPD. The historical difference between the CPI and the GDPPD for the 25 years ending 1991 is 0.3%/yr. Thus, Duquesne's IRP inflation forecast, once adjusted, translates into a GDPPD rate in the 2.8%/yr to 3.6%/yr range.

Q. Given the historical inflation data and Duquesne's own recent projections that you have described, what is your conclusion regarding Duquesne's inflation factor?

A. It is unreasonably low and should not be accepted as a basis upon which to forecast future market prices. A general input price inflation level of 3.0%/year, which is consistent with Duquesne's recent IRP and is closer to historical long-term averages, is far more reasonable.

4. Pollution Control Costs

Q. Did you review Schnitzer's assumptions about NO_X control costs?

A. Yes. I examined Exhibit Nos. MMS-2 and 4, but there is no discussion of NO_X control costs or a sensitivity case for anticipated NOx control costs.

Q. Did Duquesne consider NO_X control costs in its analysis of Duquesne's revenue requirements for its generating assets?

A. Yes. Duquesne incorporates anticipated NO_X control costs into projected Duquesne capital expenditures for each plant. The NO_X control costs are based on the requirements of the Clean Air Act Amendments ("CAAA") and Acid Rain Rule requirements. *See* Exh. RLN-6.

Q. Are the CAAA Title IV Phase I regulatory requirements the only regulatory program that aims to control NO_X emissions from Duquesne's power plants?

A. No. There are several overlapping current and proposed regulations to control NO_X emissions from power plants in Pennsylvania, including the more stringent CAAA Title IV Phase II Acid Rain Rules (see 61 Fed. Reg. 67,112); a Memorandum of Understanding (MOU) between 12 Northeastern states, including Pennsylvania, and the District of Columbia (known as the Ozone Transport Commission) that established guidelines for NO_X emission reductions among the signatories; and the recently proposed controls on NO_X emissions arising from recommendations by the Ozone Transport Assessment Group (OTAG) (see www.epa.gov/capi/capi/reganal2.html).

Q. Will these other regulations increase NO_X control costs beyond those incurred by the CAAA Title IV Phase I requirements?

A. That depends on the stringency of the other regulatory programs relative to the CAAA Title IV Phase I requirements, the current emissions of Duquesne's plants, and the ultimate form that the proposed actions take in terms of limits on NO_X emissions. For example, the CAAA Title IV Phase II requirements are more stringent than the Phase I requirements. This might imply that a utility would have to incur additional expenses to reduce emissions. Compliance with Phase II requirements, however, already may be achieved based upon previous control efforts and the plant technology. In such a case, no additional control costs would be incurred.

Further, because some NO_X regulations are only at the proposal stage, it is difficult to determine with certainty whether future regulations would increase NO_X control costs beyond those incurred by the CAAA Title IV Phase I requirements. In general, though, future NO_X regulations are expected to be more stringent than both the Title IV Phase I and Phase II regulations. For example, as proposed, EPA has estimated that its rule to control regional ozone transport through control on NO_X emissions would result in incremental (*i.e.*, additional) costs above the base case of about $1,700 per ton of NO_X reduced in the summer season in 2005 (see www.epa.gov/capi/capi/reganal2.html). To establish the base case, EPA recognized future compliance with the Title IV Acid Rain requirements as well as the Ozone Transport Commission's MOU.

Q. What is your conclusion regarding Duquesne's accounting for NO_X emission costs in its stranded cost calculations?

A. Duquesne accounted for the costs to some extent as they applied to Duquesne's plants in terms of going forward costs. However, Mr. Schnitzer did not include the costs at all in determining his price predictions. His failure to do so leads to particularly misleading results because his assumed technology, CCs as gas fired units, will be impacted to a greater extent by NO_X emission costs than will Duquesne's existing coal-fired plants. Thus, Duquesne inappropriately raised the spread between its projected costs and its expected revenues based in Schnitzer's price predictions by not accounting for NO_X emissions costs on both sides of the equation.

VIII. DUQUESNE'S OSTENSIBLE CONSUMER PROTECTION FEATURES ARE MEANINGLESS

Q. Does Duquesne propose any provisions that it contends will protect ratepayers from liabilities for excess payments of purported stranded costs?

A. Yes. It proposes two mechanisms that in its view would protect ratepayers from funding excess depreciation and amortization.

Q. Do you agree that the mechanisms provide protection to Duquesne's ratepayers?

A. No. The mechanisms are meaningless. They provide no protection whatsoever.

Q. Please describe the first of the two mechanisms.

A. The first mechanism is Duquesne's proposal to establish a trigger for an early final market valuation based upon pre-established price triggers for the years 2001 and 2002. Clayton, Statement No. 2, at 4:12-13. Under that proposal, Mr. Clayton used Mr. Schnitzer's high market price prediction for 2006, deflated to 2001 and 2002, and then applied a 75% discount factor to calculate trigger prices of $28.5/MWh for 2001 and $29.2/MWh for 2002. *Id.* at 41:14-18. According to Clayton, if those trigger prices actually were established in the market, the market price likely would be sufficiently high to allow an early end to Duquesne's proposed rates and further collection of the CTC. *Id.* at 41:18-20. Thus, Duquesne would undergo its proposed final market valuation at that time.

Q. What market evidence would Duquesne use to establish the trigger price?

A. It would use its annual solicitation for sale of firm power. Clayton, Statement No. 2, at 41:21-23. If the market price determined from one of those solicitations exceeds the pre-established values, Duquesne's final market valuation would be triggered. *Id.* at 41:23-42:2.

Q. What is wrong with that proposal?

A. The proposal is a sham. Presumably, Duquesne will conduct its annual solicitation in the same or a similar manner to the restrictive manner in which it conducted its 1997 RFP. As a result, the annual solicitation would be designed to depress prices

just as the 1997 RFP was designed to depress prices. As a result, it would be very unlikely that the prices bid in the solicitations would exceed the pre-established trigger values. As a result, the potential for the trigger actually to be implemented is almost nil.

Q. What is the second consumer protection mechanism Duquesne claims?

A. The second mechanism is Duquesne's proposed ROE spillover mechanism. Under that proposal, Duquesne would establish a collar of + or - ½% around its requested ROE of 11.5%. If the Company's earnings exceed 12%, Duquesne would establish a deferred revenue credit account to which it would record the excess earnings. If Duquesne's earnings fall below 11%, the account would be adjusted to increase Duquesne's earnings to 11%. Under Duquesne's proposal, if at any time the balance in the deferred revenue account, when netted against the Company's net book value of generating and regulatory assets, is equal to Duquesne's estimated net book value as of December 31, 2005, Duquesne's proposed final market valuation would be triggered.

Q. What is wrong with that proposal?

A. That proposal also is a sham. First, as I have previously discussed, Duquesne's estimated net book value as of December 31, 2005 is grossly inflated, for example, because of Duquesne's unreasonably high projection of future capital additions. As a result, if the balance in the account ever rose to a level sufficient to trigger the early

final market valuation, that would mean Duquesne's ratepayers had "reimbursed" Duquesne for non-existent costs that Duquesne claimed to inflate its projected net book value.

Second, Duquesne has not made any representation that it would not use write-downs to offset earnings. If it did, it could artificially depress its net earnings, but then boost them back up by taking funds out of the reserve account to get Duquesne its guaranteed 11% ROE. As a result, the ROE spillover not only does not protect ratepayers, Duquesne actually could use the ROE spillover to exacerbate ratepayers' liabilities to fund Duquesne's non-existent stranded costs. As a result, I disagree strongly with Duquesne's representations that either of its trigger mechanisms protect ratepayers at all.

IX. REMEDIES

Q. What recommendations do you have concerning Duquesne's claimed stranded costs, in light of the facts reviewed above?

A. Duquesne's claim should be rejected. Duquesne attempted to prove its entitlement to stranded cost recoveries in two ways. First, it relied upon the results of Duquesne's RFP to provide what Duquesne claims is an indication of the current market price of electricity in the region. However, as I have shown in Section III.A., the Duquesne RFP constitutes a wholesale "dump" transaction that under no scenario

can be deemed to establish the real market value of electricity in the region now or at any time in the future.

Moreover, the results of the Duquesne RFP are wholly irrelevant to Duquesne's claimed stranded costs. Nowhere in its testimony does Duquesne set forth a quantification of claimed known and measurable stranded costs based upon the Duquesne RFP and Duquesne acknowledges that it cannot do so because it does not know what the results of Duquesne's RFPs will be in any year in the future.

Instead, the only quantification that Duquesne sets forth as a basis to support its claimed entitlement to recoveries of stranded costs is based upon witness Schnitzer's computer-generated predictions of the future price of electric power. In fact, Duquesne does not provide a stranded cost estimate in this case except for amounts alleged to be remaining as of December 31, 2005. *See, e.g.*, Duquesne Statement No. 2, at p. 29:20-22. However, as shown in Section VII, in performing his study, Witness Schnitzer used unreasonable input assumptions that were designed to reduce predicted future electric generation prices to unreasonably low levels. Duquesne also used unreasonable cost assumptions to inflate its projected cost of producing electric power. The net effect of those two factors was to grossly inflate Duquesne's stranded cost claims. As a consequence, Duquesne has not proven that it has any stranded costs, at all. I have several recommendations in view of that conclusion.

A. The Unbundled Generation Component of Duquesne's Rates Should Reflect Duquesne's Costs.

Q. What is your first recommendation?

A. It is my understanding that the CTC is intended to provide for recovery of a utility's stranded costs. Having failed to demonstrate verifiable stranded costs as of January 1, 1999, Duquesne is not entitled to charge a CTC. Instead, Duquesne can collect *cost*-based rates for transmission, distribution and generation only. Particularly, the generation component of Duquesne's rates should reflect only Duquesne's actual costs of producing power and should not include amounts for accelerated depreciation and amortization and inflated cost estimates that might be necessary to produce revenues that would match Duquesne's existing revenue requirement plus the adjustment occasioned by rolling the ECR into base rates. In other words, Duquesne's ratepayers are entitled to an across-the-board rate reduction immediately.

Q. If Duquesne has no stranded costs, why shouldn't Duquesne be permitted to charge market-based prices for electric power commencing January 1, 1999?

A. Not all customers will be able to choose the supplier of their choice until January 1, 2001. Therefore, I assume Duquesne will be required to have a cost-based generation rate in place until 2001 for those customers who must continue to purchase power from Duquesne until that date.

Q. If the Commission decides that notwithstanding your analysis, it should allow Duquesne to receive revenues that Duquesne justifies by reference to computer price predictions, do you propose safeguards to ensure that Duquesne's ratepayers pay only Duquesne's legitimate stranded costs?

A. Yes. I will propose several alternative remedies for the Commission, and Duquesne as well, to consider.

B. A Goal of the 1996 Act is to Let the Market Fairly Value Electricity, Which is Accomplished Through Disposition of Generating Assets

Q. Is there an alternative to Duquesne's proposals for determining stranded costs?

A. Yes. Instead of using a wholesale "dump" sale to establish market prices, or a computer model to predict future prices and the administrative process to test such predictions and the fairness of future cost levels, Duquesne could simply let the market value its generation assets.

Q. Please describe why an option for Duquesne to sell its generation-related assets is reasonable.

A. Duquesne has not shown that it is entitled to any stranded cost recoveries because it has not shown that it, in fact, has any known stranded costs. Therefore, one option for the Commission would be to deny Duquesne any recovery. In lieu of that result, at Duquesne's option, the Commission could allow Duquesne to put its generation plants up for bid to quantify stranded costs based upon a value-maximizing sale. If

Duquesne wishes to retain any plant(s), it may submit a binding offer, in the bidding process, of its willingness to offset stranded costs by a stated amount. If Duquesne's binding offer exceeds the highest *bona fide* bid of any other market participant for that asset, Duquesne may retain the asset. The aggregate value of the prevailing high bids and any prevailing Duquesne stranded cost offset offers then would be used in calculating net stranded costs.

Q. Please describe why the asset sale option you just described can serve as an effective yardstick of stranded costs.

A. First, letting the market set the value of generation assets in order to establish stranded costs can expand opportunities for potential competitors to gain a foothold in the utility's prior service territory, which promotes effective competition in the generation market.

But there is another advantage as well. Fair market valuation -- in contrast to the dump wholesales of Duquesne -- can result from sales that afford participants flexibility to extract value from the utility's assets. A well-structured divestiture process can result in the highest value possible for those assets. Fair sales can place assets in the hands of those best positioned and best able to manage and operate the assets, and who see value not seen by current owners. Market scrutiny quantifies value that is difficult to establish and incorporate into administrative calculations,

such as Duquesne witnesses Schnitzer's and Clayton's computer model price and cost predictions.

In contrast to asset sales, a utility may be tempted in administrative proceedings to conceal potential cost savings or potential sources of value so that once a stranded cost recovery has been achieved or approved by the agency, the utility can market its assets or reduce costs solely for the benefit of shareholders.

Q. Are there other benefits to asset sales?

A. Yes. If the assets are sold, it would eliminate the need for Duquesne to recover future O&M expenses, taxes, fuel costs, and terminal values (environmental and decommissioning commitments) associated with stranded assets.

Q. Can you give examples of how asset sales explicitly capture value seen or even considered by others?

A. Yes. For instance, bids may reflect:

- exploiting value which exists (*e.g.*, environmental permits, connection to transmission grid -- such as the Brunot Island site -- and expansion potential (including nongeneration uses)) or can be added (*e.g.*, 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);

- potential to build market share, especially in regions where the buyer believes capacity ultimately will be in short supply; and

- price expectations by numerous market participants (not just the utility) who do not have a vested interest in depressing the value of the asset to inflate stranded costs.

Q. Can you provide an example of additional value resulting from the buyer's desire to acquire assets and increase market share?

A. Yes. Buyers will attempt to increase market share in generation for a number of reasons. One reason is to improve overall efficiency of their organization. By increasing their market share in a region, the buyer can spread fixed costs of operation over a larger number of facilities, thereby driving down per-unit fixed costs. Another reason to attempt to increase market share in a region is to add value to another part of the company's operation. By acquiring generating assets in a particular region, the buyer could improve the value of an affiliate's power marketing efforts in that region. Acquiring generating assets in a particular region could also increase the demand for other services that a subsidiary company provides (*e.g.*, natural gas, gas transmission).

Q. Can you provide an example of how offering numerous buyers an opportunity to buy assets enhances value?

A. Yes. Suppose a marginally profitable utility has a facility that will lose money for three years and then show a profit. A strongly profitable utility may be able to make

better immediate use of the facility's three year net operating losses for tax purposes than would a marginally profitable utility, and its bid may reflect the value of its particular circumstances. In like manner, multiple market bids will assess the future value of power, future capacity constraints, and the value of ancillary services. For example, non-utility generators have demonstrated their ability to achieve higher capacity factors, reduce capital and operating costs, reduce fuel costs and hedge fuel price uncertainty. Recent acquisitions in the independent power industry as well as the sale of the New England Electric System ("NEES") assets have demonstrated that there are many buyers anxious to compete, and in some instances pay amounts substantially in excess of net book value, for assets.

Q. Will asset sales capture fair value?

A. The market for the purchase and sale of these assets is deep, and divestiture is merely a transfer of ownership. The recent wave of utility mergers (totaling over $40 billion in 1995 and 1996) and aggressive pursuit of offshore acquisitions (*e.g.*, the RECs in the UK) and domestic opportunities (*e.g.*, Cajun bankruptcy, Big Rivers, NEES divestiture, sales of non-utility owned generating assets) indicates that the market can absorb large volumes of transactions.

Q. Can you provide specific examples which demonstrate that there is significant interest for generation assets?

A. Yes. The NEES - U.S. Generating Company transaction was consummated at $1.59 billion -- approximately $500 million more than its $1.1 billion book value. *See* "USGEN Purchase of 5,000 MW From NEES Seen Remaking Northeast Power Market," *Elec. Util. Week* (Aug. 11, 1997). The premium may be attributable to (i) the desire of USGEN to increase its presence in the New England market and (ii) synergies with its existing portfolio. This added value USGEN placed on the NEES assets provided ratepayers with additional savings that they otherwise would not have received.

Q. Do other transactions demonstrate that there is (i) an active market for generation facilities, or (ii) an opportunity to obtain prices in excess of net book value?

A. Yes. One need only look as far as the affiliate of Duquesne's merger partner, Allegheny Power Systems ("APS") to answer to that question. As I previously discussed, an APS affiliate purchased Duquesne's interest in Ft. Martin. As I also discussed, the unit was purchased for $169 million, which was more than 4.5 times Duquesne's share of Ft. Martin's net book value.

Q. Do you have any evidence that suggests the potential for Duquesne in particular to sell its generation assets at amounts in excess of book value?

A. Yes. Duquesne had a study performed for it concerning the potential divestiture of its assets. Duquesne's consultants advised that divesture provides a"[h]igher probability of achieving price above book value." Exhibit RBW-55.

Q. Do you have any evidence that suggests that there are parties willing to bid on Duquesne's generation assets if offered for sale?

A. Yes. A Merrill Lynch study for Duquesne concerning the value of Duquesne's generation plants stated that "demand for generating assets far exceeds supply as both certain utilities and IPPs race to be 'players' in generation." With respect to Duquesne's facilities, Merrill Lynch forecast "a strong reception," stating it had "identified a number of potential purchasers who are eagerly pursuing acquisitions with very few sellers." Merrill Lynch also provided Duquesne a list of a substantial number of potential buyers. Exh. RBW-56.

In addition, Central Maine Power announced on September 11, 1997, that its proposal to sell off its portfolio of more than 2,000 MW in power plants and entitlements has "generated 'substantial' interest judging from the number of responses so far." *See* "CMP Pleased With Response, Invites Binding Bids," *Megawatt Daily*, September 12, 1997. One need not endorse the specific terms of a particular asset sale plan to recognize the benefits of properly-structured market-valuation procedures.

Q. Can you identify examples where Duquesne has not reflected value in its proposed theoretical calculation of stranded costs that could be reflected in asset sales?

A. Yes. Duquesne failed in estimating stranded costs to consider, much less fully analyze:[1]

- explicit estimates of site value (not just existing value of property);
- explicit estimates of residual value;
- explicit estimates of operating cost reduction potential and comparison with best practices in the industry, or similar alternatives;
- explicit estimates of the value of ancillary services, such as voltage support, spinning reserve, black start capability, and balancing services;
- explicit estimates of likely buyer appetite, based on comparable sales (adjusted for site-specific factors); and
- explicit assessment of strategic strengths and weaknesses of Duquesne's generating facilities.

Q. Will you summarize your first recommendation, concerning the sale of assets?

A. Because Duquesne has not demonstrated an entitlement to recovery of any stranded costs, the Commission can provide Duquesne an option. Duquesne can rely on its case as filed, and it will be denied a CTC At Duquesne's election, however, Duquesne can put its generation assets up for sale, and the market will establish a real valuation. Following such a valuation, Duquesne's legitimate stranded costs will be quantifiable, known and measurable. If any costs are truly "stranded," the Commission can provide for Duquesne's recovery of those amounts. If sales of

[1] These valuations would appropriately be based on their values in a competitive market, subject to the Commission's rules and restrictions.

Duquesne's assets show Duquesne has no stranded costs, then ratepayers will not be burdened with costs that never should have been theirs to bear. Further, the sales and transfer of facilities and contract obligations can enhance true competition in Duquesne's service territory.

C. At A Minimum, Alternate Simulations to Those Relied Upon by Duquesne Should Determine Whether Duquesne Has Stranded Costs

Q. Are there safeguards that you recommend if Duquesne is authorized to recover through an ITC or a CTC any amounts determined in the administrative process?

A. Yes. If Duquesne is permitted to recover any CTC or ITC amounts pursuant to computer price predictions, the Commission can establish in advance several safeguards which will incent Duquesne to more accurately estimate prices. One such safeguard is that Duquesne should be obligated to offer power to its customers at the prices upon which stranded costs are calculated. That requirement would extend through the final date upon which prices were predicted that serve as the basis for Duquesne's stranded cost calculation.

Q. What is the justification for your remedial proposal that Duquesne should be obligated to offer to sell its power at the prices upon which stranded costs are predicated if the stranded costs are derived from computer-generated price predictions?

A. Under this scenario, Duquesne's customers already will have paid the difference between Duquesne's present (inflated) revenue level and the computer-predicted market price. Therefore, Duquesne's customers should be entitled to the benefit of that market price. If they cannot obtain power at the price predicted by the computer, but instead ultimately must pay a higher market price, they will pay twice, once through the "stranded" cost CTC or ITC charges, and again in the market price when they purchase their power supplies. That result means that consumers in the transitional environment will get the worst of both regulated and competitive worlds.

If Duquesne desires to recover stranded costs pursuant to computer predictions, than it should bear risks of forecasting error. That is exactly what it asks of its customers: that is, if the computer-predicted market price turns out to be too low, and consumers have had to pay stranded costs based on that prediction, Duquesne does not capture a windfall.

Q. Are there any conditions that the Commission would have to impose upon Duquesne in order to make this offer valid?

A. Yes. Duquesne could not dispose of or encumber its economic units if it elects to proceed with this option; otherwise, it could render itself unable to perform its agreement with the Commission.

Q. Is there another condition you would impose to protect ratepayers?

A. Yes. I would require Duquesne to establish a true-up mechanism.

Q. What is your proposal regarding such a mechanism?

A. Duquesne proposes to base its stranded costs on its lost revenue or a net present value basis. Given that Duquesne desires to use the lost revenue approach as the base line for its stranded cost determination, it is appropriate to require Duquesne to compensate customers based upon the return on equity that it will earn by avoiding full Commission scrutiny of its base rates. Duquesne predicts that it will earn equity returns averaging 14.68%. Of course, if Duquesne believes that rate is too high, that may suggest a conclusion about the revenues Duquesne seeks in this proceeding.

Q. If an administratively-determined price is the basis for any stranded cost recovery, do you have a recommendation as to the appropriate input?

A. Yes. Each of Duquesne's assumptions discussed above in Part VI depresses Duquesne's prediction of future market prices. Acceptance of those assumptions would establish Duquesne's right to collect a CTC based upon computer-driven excessive estimates to cover illusory stranded costs. If the Commission determines that an administratively-determined stranded cost is acceptable, at a minimum I would recommend correction for the errors and omission described in the next section.

X. DUQUESNE'S PROJECTIONS OF THE MARKET LINE ARE LOW COMPARED TO OTHER RECENT ESTIMATES

Q. Have you reviewed other market line projections applicable to Duquesne?

A. Yes. I examined the following market line projections prepared for or by:

- West Penn's restructuring filing;
- West Penn's analysis of its purchase of Duquesne's interest in Ft. Martin;
- Duquesne, used in generation valuation assessments for Duquesne and prepared by CS First Boston and Metzler and Associates;
- EIA, an energy-only market line prepared earlier this year; and
- William Hieronymus for PECO both as originally stated for PECO and adjusted to ECAR using a transmission rate of $6/MWh.

Q. What does your comparison show?

A. Exhibit RBW-57 shows that all those market lines are higher than Mr. Schnitzer's low market line for Duquesne in this case. Considering Schnitzer's low market line, only West Penn's market line filed in its restructuring case is lower.

Q. What is the general effect of these alternative market lines when used as measures to calculate Duquesne's potential stranded costs?

A. The higher the market line, the lower the stranded costs. This Exhibit displays present value market revenues of Duquesne's generators, assuming each market line. Although present value revenues is only a part of the stranded cost equation, changes

in present value revenues are indicative of changes in stranded costs under each market line.

Q. Please explain this comparison.

A. Witness Clayton has testified that his expected net book of $533 million (in 2005$) translates into either stranded costs of $423 million (in 2005$) with his low market price case, which according to this Exhibit has a Present Value of $3,786 million ($1998), or a positive market value of $233 million ($2005) from a Present Value revenue stream of $4,378 ($1998). (See Exh. DJC-3, p. 1.) The Ft. Martin case results in a Present Value revenue stream of $7,573 million, which is $3,195 million more positive than Duquesne's high case. Obviously, this comparison demonstrates that Duquesne has no stranded cost claim under this projection.

Q. What about the other market price forecasts?

A. Obviously, projected revenues from West Penn's forecast are very similar to Duquesne's low case and Hieronymus "corrected from PJM to ECAR," while the other cases (see for example, Duquesne's CS First Boston and Metzler) are all substantially higher than the Present Value Revenues of Duquesne's high case. Of course, none of the foregoing estimates take into account the effects of mitigation steps that have been outlined in my testimony.

Q. What do you conclude from the comparisons?

A. It is clear that Duquesne's low case is particularly exaggerated and should not be accepted as a basis to determine known and reasonable stranded costs.

XI. CONCLUSION

Q. Does this conclude your testimony?

A. This concludes my testimony at this time. However, I have referred in this testimony to Duquesne's October 16 revisions to its stranded costs calculations. HSS/ARI did not receive a readable computer disk of the changes that are incorporated in Duquesne Exhibit DJC-3 until Sunday, November 2, 1997. Therefore, I have not had sufficient time to fully evaluate all the ramifications of Duquesne's revisions. Pursuant to the Third Prehearing Order in this case, I reserve the right to respond further to Duquesne's corrections in surrebuttal testimony.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

CERTIFICATE OF SERVICE

I certify that I am serving a copy of the foregoing document on behalf of the Office of Small Business Advocate by first class mail upon the persons addressed below:

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