

VOLUME II

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BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY  
DOCKET NO. R-00974104

APPLICATION FOR APPROVAL OF  
RESTRUCTURING PLAN UNDER SECTION 2806  
OF THE PUBLIC UTILITY CODE

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Contents:

Rebuttal Testimony and Exhibits of  
Frank A. Hoffmann, Robert A. Irvin, Fred R. Allison, Mark G. Karl,  
Ralph L. Nelson, Ralph Duckworth Jr., Jeff D. Makholm, Ph.D.,  
Thomas LaGuardia, & Joseph P. Flynn Jr.

**Duquesne Statement No. 6-R**

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY  
DOCKET NO. R-00974104**

**Rebuttal Testimony  
of  
Frank A. Hoffmann**

**Contents:**

**Response to Intervenor Testimony Regarding Economic  
Development Rates, Retail Choice Phase-In, Customer  
Education, and Code of Conduct**

## REBUTTAL TESTIMONY OF FRANK A. HOFFMAN

1       **I.     INTRODUCTION**

2       Q.     Please state your name and business address.

3       A.     Frank A. Hoffmann, Duquesne Light Company, 411 Seventh Avenue, Pittsburgh,  
4             PA 15230-1930.

5       Q.     Have you previously participated in this proceeding?

6       A.     Yes. I submitted direct testimony (Duquesne St. No. 6) and various supporting  
7             exhibits with the Company's August 1, 1997 Restructuring Application. A  
8             statement of my qualifications is contained in my direct testimony.

9       Q.     What is the purpose of your rebuttal testimony?

10      A.     The purpose of my rebuttal testimony is twofold. First, I would like to correct any  
11             misinterpretations of my direct testimony by the various intervening witnesses and  
12             secondly to respond to several conclusions and/or recommendations by these  
13             witnesses that I believe lack merit. The specific subject areas of this rebuttal  
14             include, economic development, the customer selection methodology associated  
15             with the phase-in to customer choice, customer education and code of conduct  
16             issues.

17      Q.     Would you summarize your rebuttal testimony?

18      A.     First, Duquesne's proposal to eliminate Riders 8 and 20 (for existing customers) and  
19             not to unbundle Rule 4 contract pricing is wholly consistent with the economic  
20             development objectives of the region and the state. Second, Duquesne's proposed

1 customer selection methodology is a simple, equitable and objective approach  
2 giving customers opportunity for direct access in compliance with the legislation's  
3 schedule. Third, Duquesne's customer education program has been structured to  
4 effectively fulfill the Company's role as a credible source of objective information  
5 about the transition to Customer Choice while integrating that role with the PUC led  
6 implementation of the core curriculum. And lastly, to restate Duquesne's  
7 commitment to a practical Code of Conduct that ensures fair competition.

8 Q. In your direct testimony you addressed Universal Service and Energy Conservation  
9 issues. Are you going to cover these issues in your rebuttal?

10 A. Duquesne has taken a progressive approach to Universal Service that is in full  
11 compliance with the PUC's Guidelines. Based on our recent needs assessment, we  
12 conclude that the current level of funding appears to be adequate to meet the  
13 Programs' objectives. Since our original Restructuring Plan filing, Duquesne filed  
14 our Universal Service and Energy Conservation Plan with the Commission on  
15 November 3, 1997. Given the disparate views on these issues by the various  
16 intervening witnesses and the Commission's apparent interest in these important  
17 issues, Duquesne is introducing a new witness, Mr. Joseph P. Flynn Jr., to address  
18 these issues in depth. Mr. Flynn is the Director of our Customer Programs and is the  
19 principle architect of Duquesne's Universal Service and Energy Conservation  
20 Programs.

21 **II. ECONOMIC DEVELOPMENT**

22 Q. What is Duquesne's general position vis a vis economic development?

1           A.     Duquesne has been long recognized as an active leader in working with customers  
2                     and other stakeholder groups to promote the economic growth of the region. This  
3                     commitment to strengthening the regional economy remains strong and Duquesne  
4                     will continue in an active role.

5           Q.     DII witness Baron claims unequal treatment between new and existing customers  
6                     if Duquesne eliminates Riders 8 and 20 (as they pertain to existing customers).  
7                     Would there be unequal treatment?

8           A.     No. Riders 8 and 20 were originally designed to provide a discount for incremental  
9                     load and usage as an incentive for qualifying business to expand their operations and  
10                    contribute to the economic growth of the region. With the introduction of  
11                    Duquesne's unbundled rate design, as described by Duquesne witness Lahtinen, all  
12                    incremental usage for existing customers over the baseline usage used to determine  
13                    their CTC, will be billed at unit prices considerably below the bundled tariff tail  
14                    block rates. For example, based on an analysis of existing GL-rider 8 customers, the  
15                    unbundled tariff provides them with approximately 35% more savings on  
16                    incremental load. If Riders 8 and 20 were to be retained in the tariff structure in  
17                    their present form, the low tail block rates found in the unbundled tariff would be  
18                    discounted even further. This would have three adverse consequences. First,  
19                    maintaining the tariff as presently filed could be misinterpreted to mean that energy  
20                    charge discounts would also be applied to the unbundled generation charge (CGC).  
21                    This is not what Duquesne intended. To do so would mean that economic  
22                    development customers who take full requirements service from Duquesne would

1 receive power prices as low as 25% below current market prices. Competitive  
2 generation suppliers would find it difficult to compete against this below market  
3 price. Second, the discount on the already low unit prices would provide more  
4 economic incentive than necessary to stimulate the business expansion thus  
5 suggesting economic inefficiency. And third, any inequity would in fact result from  
6 preserving Riders 8 and 20 since existing customers would be receiving a "discount  
7 on a discount" whereas for new customers the Rider 9 discount would apply to only  
8 the baseline usage.

9 Q. In the interest of economic development, should the Rule 4 contracts be unbundled?

10 A. No. One would not expect any economic development effect by simply unbundling  
11 each of the Rule 4 contracts. First of all, each Rule 4 contract was developed as a  
12 mitigation strategy to attract or retain incremental load that Duquesne would have  
13 otherwise lost to a competitive alternative (e.g., end-use technology using an  
14 alternative energy, physical location outside the territory, etc.). In each instance, the  
15 customer's total economics associated with the relevant business operation (e.g.,  
16 differences in energy costs, maintenance costs, capital requirements, etc.) were  
17 considered in establishing the negotiated rate. As such, the terms and conditions of  
18 each contract are unique to the specific competitive threat. It should be noted that  
19 all contracts were priced to cover all of Duquesne's incremental costs and make a  
20 positive contribution to fixed costs thus mitigating stranded investment.

21

1 With the unbundling proposed by Duquesne, where the generation credit is  
2 established based on the *market price* of energy, the customer's economics under a  
3 unbundled Rule 4 would be unchanged. Furthermore, since the Rule 4 rate for each  
4 customer was established based on the customer's economics associated with the  
5 competitive alternative, the pricing was efficient from an economic development  
6 perspective (i.e., it was just low enough to attract/retain the incremental load for the  
7 region, yet maximized the contribution to fixed costs.)

8 Q. You mention that the Rule 4 contracts have the dual effect of supporting economic  
9 development while also being a mitigation strategy. Could you describe the effect  
10 they have had?

11 A. The economic development benefits and stranded cost mitigation under Rule 4 have  
12 been substantial since its inception. Duquesne has 18 Rule 4 Contracts in effect  
13 representing approximately 190 MW's of load. The net present value of the  
14 revenues associated with these contracts total more than \$247.5 million. If  
15 Duquesne did not have this competitive pricing, it would have lost the incremental  
16 sales associated with the competitive threat. For example, if the Rule 4 customers  
17 had each implemented their next best alternative, the total revenue from the  
18 remaining sales with bundled tariff rates would have totaled only approximately  
19 \$103 million (NPV). Without the pricing flexibility of Rule 4, the net present value  
20 of the contribution to fixed costs for the remaining sales would total only about  
21 \$62.2 million. Under the current contracts, however, the contribution to fixed costs  
22 totals \$138 million (NPV). Thus using Rule 4 to secure long-term contracts for

1 incremental load, which otherwise would have exercised a competitive alternative,  
2 has helped Duquesne to mitigate fixed costs by almost \$76 million (\$138 million -  
3 \$62.2 million = \$75.8 million NPV).

4 Q. Is it valid to view the Rule 4 pricing as a discount from existing tariff levels?

5 A. No. As described above, the Rule 4 pricing was set at a level necessary to defeat the  
6 competitive alternative after it was determined that the standard tariff schedule for  
7 the relevant customer class and load would not achieve this objective. Thus the  
8 pricing level under the standard tariff schedule as applied to the incremental load is  
9 irrelevant since the incremental load would not have been attracted/retained. Rather  
10 the customer's savings would have accrued from the competitive alternative with no  
11 incremental contribution to Duquesne's fixed costs. OCA witness Smith suggests  
12 that any Rule 4 discounts be imputed toward the CTC collections for the relevant  
13 customer classes [Page 10, Line 1]. There are two obvious problems with this  
14 position. First, as illustrated above, the alleged discount is fictitious. Secondly, the  
15 practical effect of witness Smith's suggestion will be to chill any activity under Rule  
16 4, and by extension to all economic development incentives. This is because the  
17 costs of all the incentives for economic development will be borne by Duquesne's  
18 shareholders while the benefits in terms of economic stimulus to the region accrue  
19 to the ratepayers and other stakeholder groups. Given this asymmetrical arrange-  
20 ment, Duquesne would have a disincentive to promote economic development in the  
21 region and as a result would cease promoting the economic development incentives  
22 inherent to Rule 4 and the relevant riders.

1 Q. Would you please summarize how you believe the key economic development  
2 issues discussed above should be resolved?

3 A. Given our unbundled rate designed, the claim that it is somehow "unfair" for  
4 Duquesne to eliminate economic development Riders 8 and 20, as they pertain to  
5 new incremental load, should be rejected. Furthermore, it should be recognized that  
6 the attraction/retention of customer load through the Rule 4 flexible pricing  
7 provisions is an effective economic development initiative as well as a sound  
8 mitigation strategy. As such, ratepayers throughout the region are benefitting from  
9 these contracts.

10 **III. CUSTOMER SELECTION**

11 Q. Duquesne has not advocated the "first-come, first-served" approach to customer  
12 selection as suggested in the legislation. Why not?

13 A. First of all it should be noted that, while the legislation suggests that full direct  
14 access be determined on a "first-come, first-served" basis, the final determination  
15 of the phase-in methodology is to be determined by the Commission. Duquesne's  
16 primary reservation about the first-come, first-served approach is the inherent  
17 inequities that it introduces among the customers. "First-come, first-served" is only  
18 equitable if one presumes all customers are equally informed and educated about  
19 both the benefits of competitively priced generation and the procedural aspects for  
20 enrolling in the program. (The only remaining variable therefore is motivation.)  
21 Given the extensive interest in customer education in this proceeding (which will be  
22 subsequently discussed), there appears to be a consensus that this common level of

1 knowledge does not currently exist and will be a challenge to achieve. While the  
2 competitive disadvantage issue for commercial and industrial customers is an  
3 obvious issue with this approach, residential customers who will also benefit from  
4 direct access should not be disadvantaged simply because someone else who may  
5 be better informed enrolls first.

6 Q. Does Duquesne's proposed approach using GAC's and market segments meet the  
7 objectives of the legislation?

8 A. Yes it does. The legislation requires that the phase-in be designed such that "each  
9 customer class shall have the opportunity (emphasis added) for direct access" by the  
10 prescribed dates. Duquesne's approach provides this opportunity on a fair and equal  
11 basis. Environmentalists witness Biewald suggests that the non-choosing customers  
12 (i.e., customer given the opportunity for direct access but deciding to stay with the  
13 existing service) should be allocated among the various generation suppliers serving  
14 the other customers [Page 46, Line9] presumably against the customer's wishes.  
15 MAPSA witness Russell recommends that "suppliers should be able to sign-up  
16 customers until one-third of Duquesne's total load is transferred" (emphasis added)  
17 [Page 62, Line 27]. Both of these witnesses, as well as other proponents of the first-  
18 come, first-served approach seem to have the same objective in mind, i.e., force all  
19 customers to leave their incumbent EDC whether they want to or not – an objective  
20 that is nowhere evident in the legislation. The purpose of the legislation was to give  
21 customers a choice, not to implement a new framework for regulating customer  
22 decisions.

1 Q. DII witness Baron characterized Duquesne's proposal as "vague and provides  
2 absolute control to DLC" [Page 62, Line 19]. Is this true?

3 A. Not at all. In fact, with the pilot program enrollment completed, we have relied on  
4 the customers' responses to determine the actual phase-in schedule for both the  
5 GACs and the commercial and industrial market segments. Exhibits FAH-3 and  
6 FAH-4 show the results of the pilot enrollment. FAH-3 ranks communities in  
7 Duquesne's service territory based on the percentage of total customer accounts  
8 within the designated zip code that volunteered for Customer Choice. This list  
9 serves as the basis for Duquesne's proposed phase-in schedule such that a maximum  
10 of one third of the peak load of each residential customer class shall have the  
11 opportunity for direct access. For example, in the first phase, the top 38 communi-  
12 ties listed collectively have 189,116 residential and small commercial accounts --  
13 one third of the system total. During the pilot enrollment these communities had the  
14 largest percentage of customers who expressed interest in direct access by  
15 volunteering for the pilot. Duquesne did not control who got on this list; the  
16 customers did. Similarly, Exhibit FAH-4 ranks the commercial and industrial  
17 market segments based on the percentage of total customer accounts within each  
18 segment that volunteered for Customer Choice. From this list the first phase would  
19 obviously include the entire load of all commercial/industrial customers in the  
20 "Government", "Education", "Industrial-Chemical", "Industrial-Plastics", "Utility  
21 Services", etc. Duquesne proposes to release customer segments from this list such  
22 that one third of the respective load has the opportunity for direct access by January

1 1, 1999. By extension, this list would also govern the market segment phase-in  
2 sequence for the subsequent two years. Once again, Duquesne did not control which  
3 segments were in the first phase – the customers within those segments did.

4 The simplicity of this approach is self-apparent.

5 It does not require any complicated pro-rata reductions to each subscriber's  
6 nominated load in the event of over subscription (as suggested by DII witness  
7 Baron).

8 It avoids the "land rush" approach, and the attendant operational difficulties of  
9 allowing all customers access at the same time (as suggested by Environmentalists  
10 witness Biewald).

11 It ensures that similarly situated business customers are not competitively  
12 disadvantaged (as acknowledged by OSBA witness Kalcic).

13 It allows all customer information now about when they will have the opportunity  
14 for direct access so they can plan accordingly.

15 Q. Is it feasible to accelerate the phase-in to compress the first and second years as  
16 some have suggested?

17 A. The legislation specifies that the opportunity for direct access be phased-in in  
18 accordance with the key milestone dates of January 1, 1999, 2000 and 2001. This  
19 phase-in was prescribed primarily to ensure that direct access is implemented in an  
20 orderly fashion such that all stakeholders are able to adjust to the new marketplace.  
21 DII witness Baron and Environmentalists witness Biewald have suggested a rather  
22 distorted interpretation of the legislation that would accelerate the time frame.

1           Given the recent and ongoing experiences of the pilot programs across the state, it  
2           is apparent that the phase-in as prescribed in the legislation is a prudent course of  
3           action. As we gain further experience with the pilot program, Duquesne will  
4           continue to evaluate its implementation plans for the operational feasibility and  
5           desirability of accelerating the phase-in.

6           Q.    Would you please summarize how you believe the key customer selection issues  
7           related to the phase-in of customer choice discussed above should be resolved?

8           A.    Duquesne has proposed a fair and equitable customer selection methodology that is  
9           wholly consistent with the legislation's goals for phasing-in customer choice. We  
10          recognize however, that it is desirable to have a uniform approach state-wide and  
11          that other methodologies may have comparable results. The Commission has  
12          recently issued a Request for Comment regarding Retail Access Phased Implementa-  
13          tion {M-00960890 F.0012). While the staff recommendation contained within the  
14          Commission's request appears to be flawed in various respects, Duquesne will  
15          continue to work within the Commission's process to advance our views on this  
16          matter and work toward an equitable resolution.

17          **IV.    CUSTOMER EDUCATION**

18          Q.    Has Duquesne Light proposed and implemented a customer education plan as  
19          required by the customer choice act and the Commission's orders?

20          A.    Yes. As required by the Competition Act, Duquesne Light presented a well-  
21          structured customer information and education plan to effectively convey complex  
22          topics to all of the individual segments of its customer base. The plan as designed,

1           although preliminary in part, seeks to *inform and educate* customers about electric  
2           competition, and help them understand how to evaluate their choices. The role of the  
3           consumer education plan is to provide factual, unbiased information and instruct  
4           consumers on how to comfortably use that information to make the choice that is  
5           appropriate to meet *their needs*.

6  
7           As a regulated utility, Duquesne devotes significant resources to consumer  
8           education. The Company maintains ongoing interactions with individual customers  
9           as well as various local organizations catering to the needs of specific segments of  
10          the community. These dialogues enable the Company to obtain additional insight  
11          into local education needs, then factor that insight into its overall education plan.  
12          Duquesne will continue to work with local and state government officials and  
13          community outreach organizations to deliver understandable information and  
14          education to all of its consumer segments about competition and retail choice. The  
15          Company annually establishes budgets to implement its planned consumer education  
16          and evaluation initiatives. Any expansion of this plan by the Commission could  
17          require additional funding above the established budget level. Duquesne would  
18          consider these extra funds to be transition costs, and therefore fully recoverable.  
19          These efforts may include the use of existing Company employees, facilities and  
20          other in kind services, so the identification of a specific budget and educational staff  
21          can be misleading if used as a sole means of determining the Company's commit-  
22          ment to its educational responsibility.     Instead, a better measurement of this

1 obligation is by the quality and effectiveness of its resource utilization to achieve the  
2 stated goals.

3  
4 Duquesne continues to evaluate all available alternatives to provide the most  
5 effective education efforts and allocates resources as appropriate. The Company  
6 respects the needs of its customers and does not assume that low income, elderly or  
7 non-English speaking customers are less intelligent or less capable of understanding  
8 the impending changes. Duquesne research shows that older consumers understand  
9 more than most, including high income customers, about the concepts of retail  
10 choice.

11 Duquesne also adheres to Commission requirements to disseminate general  
12 customer education materials such as the glossary of terms and dictionary. The  
13 Company participates in state-wide efforts to incorporate additional initiatives  
14 developed to support the Commission's core education curriculum, and provides  
15 support to these efforts as appropriate for the needs of Duquesne customers. The  
16 statewide Consumer Education Programs proposed by witnesses Alexander  
17 (Alexander testimony - p. 20), Muench (Muench testimony - p. 28), and Biewald  
18 (Biewald testimony - p. 24) do not exist, and may not for several months.  
19 Duquesne cannot delay the development and implementation of its own education  
20 plan since consumers are currently being exposed to decidedly biased and often  
21 inaccurate messages about competition through the media, by suppliers and from  
22 other special interest groups. Since the Company is providing objective educational

1 information, it anticipates no difficulty in coordinating its planned efforts with future  
2 statewide campaigns.

3 Q. How will this customer education be funded?

4 A. Duquesne recognizes that it has an ongoing responsibility for providing its  
5 customers with information about the safe, efficient and economical use of the  
6 utility's services. We view this role as continuing. Expenses associated with these  
7 activities at their traditional level are contained within Duquesne's cost of the  
8 service. Specifically, based on Duquesne witness Lahtinen's direct testimony (R-  
9 00974104, Volume II, Statement No. 5, Exhibit JAL-1B) there is approximately  
10 \$0.9 million in labor and \$1.4 million in non-labor expense contained within the  
11 relevant FERC accounts (i.e., 907 through 910, 913 and 916). The corresponding  
12 1998 non-labor O&M budget to implement Duquesne's customer education plan is  
13 estimated to be \$1.95 million, approximately \$550,000 above the cost of service  
14 level. It should be noted that this budget is preliminary and is based on both the  
15 customer education plan and on our proposed approach to customer selection and  
16 phase-in. The Commission has not yet specified the scope or tactics of implement-  
17 ing its core curriculum, or the level of funding needed to execute it. Should these  
18 costs be allocated to the various stakeholder groups including Duquesne, we would  
19 have to adjust our budget accordingly. While Duquesne views the customer  
20 education expense to be an inherent cost of fulfilling its role as the EDU, extraordi-  
21 nary expenses above the cost of service level are clearly driven by the unique  
22 educational requirements of the transitional period. As such, Duquesne will treat

1           these incremental expenses as transitional costs and recover them through the  
2           appropriate mechanism.

3           Q.    Does Duquesne Light's proposed education plan make it difficult for consumers to  
4           distinguish education from marketing messages?

5           A.    No. Duquesne Light clearly understands the distinctions between informational,  
6           educational and promotional material, as do its customers. OCA witness Alexander  
7           points out that "It does not take a marketing expert to realize that most Americans  
8           are quite sophisticated at discounting marketing information and the 'hype' of most  
9           commercial advertising" (Alexander testimony - pp. 17,18). Duquesne agrees with  
10          this statement and strongly believes its customers are also sophisticated enough to  
11          separate education from marketing, regardless of the banner under which the  
12          information appears. The Company's consumer education program does not attempt  
13          to influence customer behavior by motivating them to enter the market and choose  
14          a particular generation supplier. Stimulating sufficient interest to participate in a  
15          competitive market is the function of marketing communications as provided by  
16          others such as the licensed electricity generation suppliers under the supervision of  
17          the Commission. This is not the role of an effective consumer education program.

18  
19          The Environmentalist's suggestion to coordinate consumer education with disclosure  
20          and labeling requirements (Biewald testimony - p. 12) is problematic. Disclosure  
21          of sources of electricity is a supplier responsibility, and could in fact represent  
22          marketing information that might influence customer decisions about power

1 suppliers. Duquesne agrees with witness Biewald's statement that "a customer  
2 education program that presents clear and unbiased information to consumers is  
3 essential for meaningful choice" (Biewald testimony - p. 25).

4 Q. What will happen to Duquesne's marketing activities and associated expenses as its  
5 customers transition to Customer Choice?

6 A. As a regulated utility, Duquesne's marketing activities have been closely aligned  
7 with its traditional role of informing customers about the safe, efficient and  
8 economical use of its services. From its cost of service study (previously cited),  
9 Duquesne's 1996 cost for marketing (e.g. sales expense) and communications (e.g.,  
10 customer service and information) to customers was approximately \$6.7 million (as  
11 reflected in FERC accounts 907 through 916). As Duquesne transitions from a  
12 vertically integrated/regulated utility to some other structure, the separation between  
13 customer service and marketing may become more pronounced, especially as it  
14 pertains to regulated and non-regulated activities (as addressed in section V below  
15 regarding Code of Conduct). It is not at all certain, however, that the level of  
16 Duquesne's marketing-related expenses supporting the regulated business will  
17 diminish. Even functioning solely as a regulated EDU, Duquesne will still provide  
18 delivery service to the same number of franchise customers, still need to provide  
19 customer programs and still need to encourage the safe, efficient and economical  
20 usage of its services. In the event that regulated marketing-related expenses are  
21 avoidable and do diminish during the transition period, the ROE spill-over  
22 mechanism proposed in this Plan (as described by Duquesne witness Clayton in

1 Statement No. 2) will make the necessary adjustments to Duquesne's recovery  
2 period.

3 Q. Has Duquesne Light used its consumer education materials to enhance its image and  
4 position itself as a supplier in the new competitive market?

5 A. No. Duquesne's educational materials repeatedly emphasize the opportunity that the  
6 new competitive marketplace will provide to its customers, not itself. The consistent  
7 theme of the Company's educational materials is that despite all of the changes,  
8 Duquesne will provide local continuity by continuing to deliver the power, respond  
9 to emergencies and answer customer questions about their electricity service,  
10 regardless of whom they choose as a generation supplier. This has always been, and  
11 will continue to be, Duquesne's role as a regulated, electric distribution company.  
12 Contrary to Enron's claim (Muench testimony - p. 31), the Company has made no  
13 marketing references, subtle or otherwise, as to why Duquesne is superior to  
14 alternative suppliers.

15  
16 Duquesne does not agree with Enron's assertion that "attempting to label information  
17 as marketing or customer education oriented is completely unenforceable" (Muench  
18 testimony - p. 29). The Commission's involvement in the development and  
19 implementation of consumer education programs, along with their review of all  
20 education materials, will clearly eliminate this concern. In addition the Code of  
21 Conduct, to which Duquesne Light subscribes, will ensure that marketing and  
22 education activities remain separate.

1 Q. Has Duquesne conducted research to determine what its customers already know  
2 and how they want to learn more about customer choice?

3 A. Yes. Duquesne conducts monthly research to determine its customers' knowledge  
4 of electric competition legislation, what competition will mean to their electric  
5 service, and how they want to receive information about customer choice. The  
6 Company's ongoing research shows that most customers (88% - Overall 1997) claim  
7 to be aware of changes in the electric industry, and nearly two-thirds (64% - August  
8 1997) recall that they can soon choose the company that produces their electricity  
9 (September 1997 residential survey). Duquesne specifically researched awareness  
10 and perceptions of changes in the electric utility industry among energy decision-  
11 makers in high income households (>\$50,000), older households (50 years of age  
12 or older) and mixed residential customers (March 1997 residential focus groups).  
13 Customers in the older group tended to have a more extensive knowledge of changes  
14 occurring in the electric industry than either of the other groups, and demonstrated  
15 a solid understanding of the differences between the generation and distribution of  
16 electricity.

17  
18 Duquesne does not share Enron's view that "there is no reason for Duquesne to place  
19 its name on any customer education communications" (Muench testimony - p. 31).  
20 Customers naturally turn to a company that they recognize and feel comfortable with  
21 to ask questions and learn more about the issues relating to competition and  
22 restructuring. They also expect the Company to distribute education materials

1 developed specifically for Duquesne customers under the "corporate banner" since  
2 they are still customers of Duquesne Light. In fact, 78% of Duquesne's customers  
3 reported that they would find it useful to get educational information about customer  
4 choice from Duquesne Light (January 1997 residential survey). High SES  
5 consumers were more likely to say they wanted to receive information through  
6 technological channels (i.e., via cable or Internet); whereas other customers were  
7 more likely to want to learn from a "live" person, either in-person or by telephone  
8 (March 1997 residential focus groups). It is important for consumers to have a local  
9 source for information, and the use of the Company's name and toll-free hotline  
10 provide them with such a source. Accordingly, Duquesne has incorporated these  
11 and other research findings into the implementation of its education plan.

12 Q. Has Duquesne Light conducted research of pilot program participants in other states  
13 to determine what information and methods were most effective in the education  
14 process, and used that research to improve its overall plan and education materials?

15 A. Yes. Duquesne conducted an analysis of pilot programs in New Hampshire,  
16 Massachusetts and Illinois (March 1997) specifically focusing on customer  
17 education efforts and customer responses to those efforts. Surveys of customers in  
18 the New Hampshire pilot indicated that more than two-thirds (68%) said bill inserts  
19 were a *very effective* way to educate consumers about retail competition, over one-  
20 half (53%) said direct mail would be *very effective* and nearly one-half (49%) said  
21 a toll-free telephone number would be *very effective*. (January 1997 Survey Report  
22 of Retail Competition Pilot Program prepared for NH Public Utilities Commission).

1 Duquesne has incorporated these and other findings into its education and evaluation  
2 plans. The Company initially informed customers of the move toward retail choice  
3 and pilot programs via bill inserts and feature articles in the ServiceLine newsletter  
4 inserted in all residential electric bills. Duquesne direct mailed copies of the  
5 advertorials to numerous opinion leaders in most residential communities, and  
6 established a toll-free hotline to respond to consumer questions about the new  
7 legislation and the impending switch to a competitive electric generation market.  
8

9 Witness Alexander states that "... research of pilot program participants have  
10 concluded that customers want information and education about electric competition  
11 from neutral parties, such as newspapers, television and government organizations"  
12 (Alexander testimony - p. 10). While surveys of participants in the New Hampshire  
13 pilot show that consumers *expected* these sources to take lead responsibility for  
14 educational efforts, the research also shows that the number of participants who  
15 completely understood the pilot was very similar when compared by receipt of  
16 information from these same neutral sources (Newspapers - 55.3%, Television -  
17 57.4% NHPUC - 58.8%), and from a potentially "biased" source (Public Utility -  
18 55.7%). This suggests that the neutrality of the information source may be less  
19 relevant to educational effectiveness than the utility of that information. Company  
20 research of its own customers shows that only 9% find Duquesne Light *not at all*  
21 *believable* when it talks about issues that concern customers, while 78% found it

1            *useful* to get educational information from Duquesne (September 1997 residential  
2            survey).

3            Q.    How does Duquesne Light's education program prepare consumers to be informed  
4            shoppers for electricity and electricity suppliers?

5            A.    By necessity, Duquesne assumed the role of chief information source about electric  
6            restructuring because there were few sources as clearly accessible or recognizable  
7            to the general public. Duquesne's education plan demonstrates that there are  
8            distinct phases to a consumer's exposure to the onset of electric competition. It also  
9            identifies specific goals for each phase that mirror the objectives established by the  
10           Commission as set forth in their Final Order on Duquesne's pilot program (as  
11           entered August 29, 1997). The strategies for attaining these goals are evident in the  
12           stated purpose indicated for each of the key activities. The activities introduce the  
13           relevant information needed by consumers to understand and participate in each  
14           phase of the transition to retail choice. The approach builds on previous knowledge  
15           and allows consumers to establish their own comfort level with the current  
16           information before moving on to the next phase.

17  
18           The information stage establishes basic awareness of the changes occurring in the  
19           electric utility industry, and uses Duquesne Light as a familiar reference point for  
20           customers to understand how these changes will affect common relationships  
21           associated with their own electricity service. The consistent theme is that while

1 many things are changing, others will remain the same and there will always be  
2 familiar resources in the local community to guide the way.

3  
4 The solicitation, enrollment and administration phases of the education plan  
5 currently focus on the pilot program, but similar phases will exist for the transition  
6 to competition. Because the Commission has not finalized the procedures for  
7 transition, current education materials and initiatives focus primarily on Duquesne  
8 Light pilot participants. Subject matter is consistent with the key areas defined by  
9 the Commission's core curriculum. The information provides facts about how the  
10 pilot works and what consumers have to do to make informed decisions about  
11 participation. Duquesne tested the content of this material with focus groups of high  
12 income, older and mixed residential consumers, and overall impressions of the  
13 content were generally quite good. Most customers felt the information was useful,  
14 and generally limited their criticisms to the format of the package (which changed  
15 for the published document).

16  
17 Consistent with research findings of pilot participants in other states, Duquesne  
18 customers particularly want information about suppliers, and how to accurately  
19 calculate savings. To address these concerns, the Company mailed copies of the  
20 Commission's licensed supplier list to all participants, and included relevant  
21 questions to ask those suppliers about their generation service and rates. Duquesne  
22 also provided detailed instructions on the sources of potential savings as a pilot

1 participant. The pilot information provided a simple worksheet that enabled  
2 consumers to use their own monthly electric bill to apply the pilot program credits,  
3 then factor in the generation supplier's offer to determine potential savings as  
4 compared to their current bill. This approach enabled all pilot participants to  
5 evaluate the true impact on ultimate savings of different offers by separating the  
6 pilot incentives from the actual prices quoted by the suppliers. Using an "apples-to-  
7 apples" comparison of supplier prices, un-obscured by potentially misleading  
8 savings claims, enables consumers to truly shop for the best offer rather than the best  
9 average savings claim.

10 Q. Has Duquesne Light developed a plan to evaluate the effectiveness of its consumer  
11 education plan?

12 A. Yes. As the pilot progresses, and the Commission refines the rules of competition,  
13 Duquesne will continue to conduct detailed research to assess overall knowledge as  
14 well as evaluate customers' experience with the competitive market and choosing a  
15 generation supplier. The Company disagrees with witness Colton's statement that  
16 it "provides no mechanism to evaluate and adjust its consumer education program  
17 as it is implemented (Colton testimony - p. 26). Duquesne submitted a Customer  
18 Choice Pilot Evaluation Plan as part of its compliance filing to describe the specific  
19 information it will gather, compile, analyze and report to provide insights into the  
20 efficacy of the retail choice pilot program. The plan also describes when and how  
21 it will use established research techniques appropriate to the stated evaluation  
22 objectives.

1           The Customer Education Plan identifies specific areas in each phase of the plan  
2           where these evaluation results will help assess the validity of the program and guide  
3           changes where appropriate. Duquesne recognizes that the ongoing evaluation and  
4           adjustment of its consumer education efforts are crucial to the introduction of  
5           customer choice. Witness Colton proposes adoption of his 11-step plan for  
6           evaluation of consumer education efforts (Colton testimony - p. 26). While this plan  
7           is one way of approaching the issue, it is not the only workable method to evaluate  
8           the effectiveness of education initiatives. Duquesne believes its own evaluation plan  
9           will clearly address the issues inherent in communicating the changes occurring in  
10          the electricity industry.

11         Q.     Does Duquesne support the development of a commission-led statewide consumer  
12                education plan?

13         A.     While a centralized approach, as suggested by Enron, Environmentalists, and OCA,  
14                is certainly one way to manage consumer education, there is no evidence to support  
15                the claim that this is the most efficient way to reach all Pennsylvania households  
16                (Alexander testimony - p. 22), or that it makes the most sense (Muench testimony -  
17                p. 28). Duquesne Light recognizes the importance of public input into educational  
18                messages; however, the creation of a "Consumer Education Joint Committee" as  
19                suggested by the Environmentalists (Biewald testimony - p. 24) to control content  
20                and timing of the Company's messages is neither practical nor necessary. It adds  
21                needless layers of bureaucracy, time and expense to a review process that is

1 currently adequate and thorough. There is no evidence to support the suggestion  
2 that formation of a Committee will result in better communications than exist.

3  
4 The demographic profiles and resulting educational needs of consumers throughout  
5 the state vary from one service territory to the next, so a one-size-fits-all approach  
6 is inappropriate. Duquesne representatives throughout the company routinely gather  
7 customer input on the information needs unique to our service area in addition to its  
8 ongoing formal customer research. A combination of centralized and decentralized  
9 messages coordinated at the local level may be more appropriate to address these  
10 issues.

11  
12 Duquesne acknowledges the appropriateness of a significant Commission role in  
13 statewide consumer education efforts, provided the Commission's activities do not  
14 supplant Duquesne's initiatives addressing the specific educational needs of  
15 consumers in its service area. The development of the core curriculum to establish  
16 basic educational objectives and provide key information messages is one example  
17 of how the Commission currently serves this capacity. Review and oversight of  
18 education efforts by electricity generation suppliers, special interest groups and local  
19 distribution companies to ensure consistent themes is another appropriate function  
20 for the Commission's statewide efforts. Duquesne could also support the  
21 Commission's role in establishing uniform criteria for evaluating the effectiveness  
22 of consumer education activities statewide, provided the Commission develops these

1 criteria with advice and input from major stakeholders, including the local  
2 distribution companies. Duquesne disagrees with the inferences of witnesses  
3 Colton, Biewald and Alexander that a Commission-led or Commission-supervised  
4 evaluation effort is the *only* effective way "...to make sure that the message about  
5 customer choice is understood, and determine where further educational efforts are  
6 needed..." (Alexander testimony - p. 25).

7 Until the nature and design of the state-wide program are complete, Duquesne does  
8 not support the blind allocation of funding, nor can it commit millions of dollars to  
9 capitalize state-wide efforts that may prove inappropriate to local needs or redundant  
10 to ongoing Company efforts (Colton Exhibit RDC-11 - pp. 1,2). Duquesne is also  
11 of the opinion that any expenses related to consumer education prescribed by the  
12 Commission should be fully recoverable, and does not support the Environmental-  
13 ists' position that the use of ratepayer dollars be prohibited if an advisory committee  
14 does not approve the Company's education materials (Biewald testimony - p. 27).

15 The Company could support witness Alexander's testimony that the state-wide plan  
16 be funded by a combination of resources from the Commission itself, the distribu-  
17 tion companies and other governmental, educational and non-profit organizations  
18 (Alexander testimony - p. 26), provided the electricity generation suppliers also  
19 participate as a funding source. As the principle beneficiaries of the education  
20 efforts, all suppliers who have applied for, or received licenses to sell electricity in  
21 the state of Pennsylvania must also be required to contribute to the funding of any

1 state-wide education and or evaluation program in an amount proportionate to their  
2 share of retail customers throughout the state.

3 Q. Could you summarize Duquesne's position regarding its approach to customer  
4 education?

5 A. Duquesne has submitted to the Commission its Customer Information and Education  
6 Plan that is designed to meet the Commission's stated objectives regarding customer  
7 education. We agree with the Commission that the responsibilities for customer  
8 education should be shared between the Commission and the EDU, with input from  
9 the relevant stakeholder groups. The customer education initiatives developed by  
10 Duquesne and the Commission will focus on meeting the customer education  
11 requirements unique to the transitional period. As such, the new education programs  
12 are expected to require extraordinary expenditures to implement (i.e., above  
13 customer information expenses contained within the Restructuring Plan's 1996 cost  
14 of service) albeit just during the three-year phase-in period. Therefore, any customer  
15 education expenditures above the existing cost of service level should be recovered  
16 by the EDU as a transition cost, possibly through the Universal Service Charge.

17 **V. CODE OF CONDUCT**

18 Q. Has Duquesne proposed an effective Code of Conduct?

19 A. Yes. The Code of Conduct adopted by Duquesne is wholly consistent with that  
20 proposed by the Pennsylvania Electric Association for the pilot program and  
21 subsequently accepted by the Commission. It is interesting to note that the only  
22 commentators on Duquesne's Code of Conduct were ENRON and MAPSA, parties

1           which have a vested interest in taking positions which would handicap the Electric  
2           Distribution Utilities and/or its affiliates at the expense of the consumer. Other  
3           intervenor groups in this proceeding who would be expected to have a more  
4           objective view of Code of Conduct issues did not take issue with Duquesne's  
5           proposed policies. Contrary to MAPSA witness Russell's belief (p. 47, line 8),  
6           Duquesne is currently complying with the proposed Code of Conduct. Furthermore,  
7           Duquesne has operated under a Commission approved Affiliated Interest Agreement  
8           since 1989 [Docket G-890176].

9           Q.     Does Duquesne expect to modify its Code of Conduct in the future?

10          A.     As recognized by the members of the Competitive Safeguard Working Group, there  
11           are many issues that are complex and remain contentious among them and to date  
12           have not been resolved through consensus. The relevant issues for the most part are  
13           generic in nature and not unique to Duquesne. As a result we expect that they will  
14           be addressed in a generic proceeding by the Commission through the issuance of  
15           regulations after the Commission has received comment and input from all  
16           interested parties. The outcome of that proceeding may necessitate as yet  
17           unspecified modifications or additions to Duquesne's Code of Conduct. Should the  
18           outcome of the generic proceeding so dictate, Duquesne will obviously adjust its  
19           Code of Conduct to be in full compliance.

20          **VI. CONCLUSION**

21          Q.     Does this conclude your testimony?

22          A.     Yes it does.

Residential and Small Commercial Transition Groups

FIRST 1/3 OF MUNICIPALITIES - JANUARY 1999

Zip Code	Municipality	Total Accounts	% Interest
15275	Parkway West	2	100.00%
15084	Tarentum	18	33.33%
15021	Burgettstown	15	26.67%
15071	Oakdale	306	24.18%
15090	Wexford	26	23.08%
15243	Scott	4,727	18.40%
15102	Bethel Park	1,543	18.08%
15024	Cheswick	1,162	18.07%
15075	Rural Ridge	115	17.39%
15142	Presto	264	17.05%
15037	Elizabeth	94	17.02%
15236	Pleasant Hills	11,026	16.80%
15234	Castle Shannon	7,018	16.13%
15049	Harwick	273	16.12%
15050	Hookstown	1,078	15.58%
15222	Golden Triangle	1,353	15.45%
15228	Mt. Lebanon	7,433	15.42%
15123	West Mifflin	52	15.36%
15026	Clinton	1,419	15.15%
15668	Murrysville	33	15.15%
15131	McKeesport	3,981	15.00%
15101	Allison Park	9,435	14.49%
15017	Bridgeville	564	14.36%
16115	Darlington	42	14.29%
15227	Brentwood	13,309	14.28%
15108	Coraopolis	16,060	14.00%
15044	Gibsonia	8,066	13.91%
15146	Monroeville	13,550	13.82%
15239	Plum	8,486	13.70%
15043	Georgetown	1,028	13.42%
15220	Wabash	9,388	13.26%
15143	Sewickley	6,927	13.25%
15216	South Hills	12,202	13.08%
15217	Squirrel Hill	12,017	13.04%
15235	Penn Hills	17,799	12.93%
15006	Bairdsford	218	12.84%
15229	West View	6,661	12.79%
15237	McKnight	11,406	12.70%

TOTAL 189,116

SECOND 1/3 OF MUNICIPALITIES - JANUARY 2000

Zip Code	Municipality	Total Accounts	% Interest
15116	Glenshaw	6,139	12.86%
15005	Baden	3,890	12.37%
15068	New Kensington	1,556	12.32%
15147	Verona	8,289	12.26%
15126	Findlay	1,181	12.19%
15226	Brookline	6,747	12.18%
15202	Bellevue	10,809	12.16%
15065	Trafford	1,877	12.04%
15137	North Versailles	5,376	11.94%
15136	McKees Rocks	10,794	11.88%
15009	Beaver	6,909	11.84%
15034	Dravosburg	1,099	11.74%
16063	Zelienople	206	11.65%
15106	Carnegie	9,729	11.61%
15042	Freedom	3,146	11.54%
15092	Winton	52	11.54%
15122	West Mifflin	9,648	11.54%
15112	East Pittsburgh	1,977	11.48%
15207	Hazelwood	6,225	11.42%
15007	Bakerstoan	206	11.17%
15225	Neville Island	755	11.13%
15218	Swetsvale	7,954	10.99%
15642	North Huntingdon	55	10.91%
15035	East McKeesport	1,278	10.88%
15205	Crafton	11,592	10.78%
15056	Leetsdale	630	10.63%
15139	Oakmont	3,564	10.55%
15210	Mt. Oliver	14,126	10.50%
15204	Corliss	4,235	10.48%
15051	Indianola	249	10.44%
15221	Wilkinsburg	18,280	10.27%
15213	Oakland	8,468	10.21%
15001	Aliquippa	15,844	10.21%
15003	Ambridge	6,543	10.21%

TOTAL 189,410

THIRD 1/3 OF MUNICIPALITIES - JANUARY 2001

Zip Code	Municipality	Total Accounts	% Interest
15133	McKeesport	3,242	10.18%
15238	Fox Chapel	5,262	10.13%
15025	Clairton	5,610	10.04%
15061	Monaca	5,889	10.02%
15048	Glenwillard	310	10.00%
15052	Industry	1,813	9.92%
15145	Turtle Creek	4,061	9.87%
15212	Lower North Side	16,305	9.80%
15027	Conway	1,098	9.67%
15209	Millvale	6,147	9.52%
15214	Observatory	6,819	9.25%
15074	Rochester	4,487	9.25%
15066	New Brighton	5,878	9.17%
15215	Sharpsburg	6,337	8.98%
15132	McKeesport	11,048	8.89%
15059	Midland	2,324	8.82%
15045	Glassport	2,522	8.80%
15081	South Heights	296	8.65%
15211	Mt. Washington	6,580	8.63%
15208	Homewood	6,128	8.44%
15010	Beaver Falls	7,553	8.20%
15223	Etna	4,001	7.97%
15203	Carson	6,124	7.95%
15206	East Liberty	15,950	7.87%
15110	Duquesne	3,488	7.83%
15148	Wilmerding	1,564	7.74%
15233	Kitbuck	1,659	7.66%
15232	Shadyside	6,721	7.65%
15091	Wildwood	108	7.41%
15104	Braddock	5,304	7.35%
15120	Munhall	9,906	7.32%
15201	Arsenal	7,485	6.97%
15077	Shippingport	116	6.90%
15140	Pitcairn	15	6.67%
15224	Bloomfield	5,886	6.63%
16059	Valencia	110	6.36%
15219	Uptown	5,758	5.94%
15279	Pittsburgh	203	3.94%
15032	Curtisville	1	0.00%
15076	Russellton	1	0.00%
15080	Glasgow	1	0.00%
15115	Glenfield	5	0.00%
15134	McKeesport	2	0.00%
15244	Montour	1	0.00%

TOTAL 183,886

## Commercial/Industrial Market Segment Raking

Market Segment	Total Accounts	Volunteered Accounts	Percent of Total
<b>Government Total</b>	1,728	911	52.72%
<b>Education Total</b>	985	509	51.68%
<b>Industrial - Chemicals Total</b>	125	46	36.80%
<b>Industrial - Plastics Total</b>	64	21	32.81%
<b>Utility Services Total</b>	1,801	577	32.04%
<b>Retail Foods Total</b>	968	308	31.82%
<b>Industrial - Steel Total</b>	458	142	31.00%
<b>Retail Restaurants Total</b>	2,382	675	28.34%
<b>Industrial - Glass Total</b>	148	40	27.03%
<b>Retail Merchandise Total</b>	4,733	1,195	25.25%
<b>Office Buildings Total</b>	7,931	1,864	23.50%
<b>Industrial - Other Total</b>	1,238	284	22.94%
<b>Healthcare Total</b>	1,813	352	19.42%
<b>Mining Total</b>	57	9	15.79%
<b>Services Total</b>	29,929	4,693	15.68%
<b>Wholesale Trade Total</b>	1,535	194	12.64%
<b>Construction Total</b>	1,349	159	11.79%
<b>Agriculture Total</b>	129	13	10.08%

**Duquesne Statement No. 7-R**

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY  
DOCKET NO. R-00974104**

**Rebuttal Testimony  
of  
Robert A. Irvin**

**Contents:**

**Response to Intervenor Testimony Regarding  
Transmission and Ancillary Services**

## REBUTTAL TESTIMONY OF ROBERT A. IRVIN

1 Q. Please state your name and business address.

2 A. My name is Robert A. Irvin and my business address is 411 Seventh Avenue,  
3 Pittsburgh, Pennsylvania 15230-1930.

4 Q. What is the purpose of your testimony?

5 A. To rebut the testimony of ENRON witness Lynn R. Coles dated November 7,  
6 1997.

7 Q. Mr. Coles's testimony at page 3, line 7 questions the availability of firm and non-  
8 firm point-to-point service in addition to network transmission service. What is  
9 the availability?

10 A. Duquesne will make available point-to-point service to any eligible customer in  
11 accordance with FERC rules. I note, however, that for purposes of the pilot  
12 program, Duquesne, like most other Pennsylvania utilities, treated all participat-  
13 ing customers as network service customers. I am not aware of any complaints  
14 regarding this treatment.

15 Q. Mr. Coles' testimony at p.3, line 13 recommends adoption of his "Pro Forma  
16 Supplier Tariff", his Exhibit 5, LRC-2. Do you agree with his recommendation?

17 A. No, because it is unnecessary and redundant. The matters covered by it are  
18 adequately covered elsewhere. For example, Section 2, Energy Delivery Service  
19 by the Electric Distribution Company ("EDC"), is covered by a supplier becom-  
20 ing a transmission customer under DLC's FERC OATT.

1 Section 3.2, Supplier License requires licensure by the Commission, which is  
2 already a PAPUC requirement as is compliance with Standards of Conduct,  
3 Section 3.3.

4 Section 3.5, Transmission Rights Outside the Control Area, appears to be  
5 mistitled but the right to transmit within the host control area is provided by a  
6 supplier becoming a Transmission Customer under DLC's OATT.

7 Section 4.1, Duty to Cooperate, is covered by ECAR rules.

8 Section 4.2.3, Daily Supplier Identification of Source of Supply Scheduling  
9 System Control and Dispatch Service, is covered by NERC scheduling rules.

10 Section 4.2.4, Supplier Supply Obligation, is covered under DLC's FERC OATT,  
11 Attachment G and/or Attachment K.

12 Sections 4.2.5, Energy Imbalance Service, Section 4.2.6, Other Ancillary Ser-  
13 vices, and Section 4.3.2, Payments for Energy Imbalance Service, are covered  
14 under DLC's FERC OATT, as amended.

15 Appendix A, Supplier Agreement Form, is covered by a supplier becoming a  
16 Transmission Customer under DLC's FERC OATT.

17 Q. Mr. Coles' testimony at p.3, line 19 recommends that charges to suppliers be  
18 reasonable and minimum contract periods should be reduced. What is your  
19 position?

20 A. DLC's charges to suppliers have been approved by FERC. I am not aware of any  
21 "minimum contract period", imposed by Duquesne, and DLC permits the  
22 supplier to change his ancillary service options from time to time.

1 Q. Mr. Coles' testimony at p. 6, line 19 states DLC requires "customers to purchase  
2 their own transmission service and three of the ancillary services. Suppliers  
3 should be allowed to obtain all necessary components of transmission for their  
4 customers." What is the reality?

5 A. Mr. Lahtinen's testimony describes Duquesne's position regarding ancillary  
6 services in more detail. As indicated in my direct testimony, however, Duquesne  
7 will allow suppliers to competitively procure ancillary services pursuant to the  
8 standards and restrictions contained in Order 888.

9 Q. Mr. Coles' testimony at p. 7, line 17 states that "DLC's approach by using the  
10 open access rate "deadband" of 1.5% and penalties for not meeting these tight  
11 requirements is wrong for the retail access situation." What is your position?

12 A. The requirements noted by Mr. Coles are FERC requirements. However, DLC  
13 requested, and FERC trial staff has agreed to a settlement under which, an  
14 energy imbalance option available to all suppliers which eliminates the  $\pm 1.5\%$   
15 deadband and provides a settlement for energy imbalance based on DLC's  
16 System Lambda.

17 Q. Mr. Coles' testimony at p. 8, line 3 discusses DLC's provision to suppliers of  
18 estimated load shapes and notes that the customer's actual load shape may be  
19 different. What is your position?

20 A. DLC offers to provide to suppliers load patterns which may be representative of a  
21 customer's usage pattern under DLC's rates. However, once the customer  
22 becomes the responsibility of the supplier, the supplier assumes the responsibility

1 for responding to the variations in that customer's load. DLC has no control over,  
2 or interest in, pricing arrangements or other terms and conditions between a  
3 supplier and his retail customer which could result in the customer changing his  
4 pattern of use from his pattern when he was a bundled tariff customer of DLC.

5 Q. Mr. Coles' testimony at p. 9, line 16 states "Since Duquesne calculates the hourly  
6 supplier obligation to serve a suppliers load, it is unfair to charge the supplier a  
7 penalty when the load obligation total determined by Duquesne does not match  
8 the actual system hourly load." Is this correct?

9 A. No. The supplier information which was made available at DLC's supplier  
10 conference on September 26, 1997 and which has been and is available on the  
11 internet places the responsibility on the supplier for projecting and scheduling  
12 into DLC's control area the aggregate hourly load requirements of the supplier's  
13 customers. Thus, Duquesne does not "calculate the hourly supplier obligation"  
14 for purposes of scheduling power to its retail customers.

15 Q. Mr. Coles' testimony at p. 11, line 4 states "Furthermore, FERC has explicitly  
16 provided for scheduling, dispatch and control and energy imbalance services for  
17 wholesale and state-authorized retail transactions as part of Open Access trans-  
18 mission tariffs. These arrangements provide the foundation for energy imbalance  
19 service to Suppliers and customers under Pennsylvania' retail access." What is  
20 your comment?

1           A.     I agree with Mr. Coles' statement. The procedures which DLC will use to  
2                   implement the Pennsylvania Pilot program are those which have been provided  
3                   by FERC.

4           Q.     Mr. Coles' testimony at p. 16, line 9 in response to a question concerning plan-  
5                   ning reserves states "Regional pools such as ECAR have found it economic to  
6                   have shared reserve responsibility, and use a percentage planning reserve require-  
7                   ment rather than having each utility provide its own reserves" Do you have a  
8                   comment?

9           A.     Yes. This statement is included in Mr. Coles' response to a question concerning  
10                  planning reserves, but the statement refers to the current ECAR practice of  
11                  sharing operating reserves. The ECAR companies do not share planning re-  
12                  serves.

13          Q.     Does this complete your rebuttal testimony?

14          A.     Yes.

**Duquesne Statement No. 8-R**

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY  
DOCKET NO. R-00974104**

**Rebuttal Testimony  
of  
Fred R. Allison**

**Contents:**

**Response to Intervenor Testimony Regarding Unbundling of  
Revenue Cycle Services, Application of Customer Payments, and  
Customer Service Procedures**

## REBUTTAL TESTIMONY OF FRED R. ALLISON

1       **I.     Introduction**

2       Q.     Please state your name and business address.

3       A.     Fred R. Allison, 411 Seventh Avenue, Pittsburgh, Pennsylvania 15230-1930.

4       Q.     Did you present written direct testimony in this proceeding?

5       A.     Yes. I submitted direct testimony, Duquesne Statement No. 8, in the  
6             August 1, 1997, Duquesne Light Company Restructuring Plan filing.

7       Q.     What issues will you address in your rebuttal testimony?

8       A.     I will address the following major issues which witnesses for intervenors Enron  
9             Power Marketing, Inc. (ENRON), Mid-Atlantic Power Supply Association  
10            (MAPSA), New Energy Ventures (NEV) and the Office of Consumer Advocate  
11            (OCA) identified in their written direct testimony:

- 12           •     Should revenue cycle services, i.e., metering, meter reading, billing,  
13                 customer payment processing, and collection, be unbundled from regulated  
14                 distribution functions at this time and be provided competitively?
- 15           •     Is the proposed method of applying payments from customers to whom  
16                 Duquesne renders consolidated bills reasonable and consistent with Penn-  
17                 sylvania Public Utility Commission (Commission) requirements?
- 18           •     Are Duquesne's proposed customer service procedures consistent with the  
19                 Guidelines for Maintaining Customer Services at the Same Level of  
20                 Quality as ordered by the Commission?

1 Q. Is your rebuttal testimony organized around these three topics?

2 A. Yes, it is. Each is addressed in turn.

3

4 **II. Unbundling Of Revenue Cycle Services**

5 Q. Several intervenors have suggested that Duquesne unbundle its revenue cycle  
6 services. Can you please summarize their positions?

7 A. I will try. OCA witness Alexander states that the PUC should not finalize a  
8 restructuring plan that assumes metering and billing will continue as monopoly  
9 services. (Alexander direct at pp. 41-42) MAPSA witness Russell proposes a list  
10 of metering and billing options that he believes Duquesne should implement.  
11 (Russell direct at pp. 42-46) Enron has several witnesses that address this subject.  
12 Enron witness Muench argues that the PUC should presume all services are subject  
13 to competition and asserts that the unbundling of billing as well as other non-wire  
14 services is important for competition because these services represent such a large  
15 proportion of small customers' monthly bills. (Muench direct at pp. 5-6) Enron  
16 witness Steffes claims that permitting competition means unbundling all services  
17 that a utility currently embeds in its service - transmission, distribution, metering,  
18 billing, and customer information services. (Steffes direct at p. 5) Enron witness  
19 Brown concludes that the PUC should order Duquesne to unbundle non-wire  
20 services as part of their restructuring plans. (Brown direct at p.22) Mr. Boonin and  
21 Ms. Day on behalf of NEV also contend that consumers should be allowed to

1 choose their provider of metering, meter reading, billing and information services  
2 through open market competition. (Day direct at p. 4 and Boonin direct at p. 21)

3 Q. What is your response?

4 A. I have three major points:

- 5 • First, Duquesne believes that it would be inappropriate to unbundle reve-  
6 nue cycle services in this proceeding as supported by the Commission's  
7 recent Proposed Rulemaking Order Regarding Advanced Meter Deploy-  
8 ment for Electricity, 52 Pa. Code 57.250-57.257, Docket No. L-0097  
9 (hereafter referred to as the "Proposed Rulemaking").
- 10 • Second, if at some later date it becomes appropriate to unbundle certain  
11 services, Duquesne will be prepared to do so.
- 12 • Third, Duquesne's prior commitment to install the Customer Advanced  
13 Reliability System (CARS) will provide better distribution service at lower  
14 cost and is pro customer choice.

15 I describe each of these points in more detail in the testimony that follows.

16

17 **A. It Is Inappropriate To Unbundle Revenue Cycle Services In This**  
18 **Proceeding**

19

20 Q. Please summarize your first point.

21 A. Certainly. First of all, numerous important issues need to be resolved prior to  
22 unbundling of revenue cycle services in order to ensure reliability, safety, customer  
23 protections, and the integrity of the current system. Secondly, the PUC has already

1 established a collaborative process to address several of these issues on a generic  
2 basis across Pennsylvania. Thirdly, retail access can move forward as planned  
3 without unbundling these services now. Therefore, I recommend that the PUC  
4 wait until this collaborative process is completed before making any decisions.  
5 This general approach is supported in the Commission's recent Proposed  
6 Rulemaking.

7 Q. Please explain.

8 A. The Commission "concludes that advanced metering is not an essential require-  
9 ment for all customers to participate in the competitive generation market at this  
10 time...The Commission does not believe that it is necessary at this early stage of  
11 electric generation competition to unbundle metering from distribution ser-  
12 vices...and concludes that metering should remain a regulated function of the EDC  
13 at this time." (Proposed Rulemaking, pp.11-12)

14 Q. Do you think the same logic applies to other revenue cycle services, such as billing  
15 and customer services?

16 A. Yes, I do. Establishing competition in the generation market should be the first  
17 priority. Efforts should be focused on getting the generation market structure in  
18 place and developing the necessary policies, interactions and communication  
19 procedures. It already requires a significant effort to complete these tasks. If the  
20 Commission is interested in pursuing unbundling of revenue cycle services, this  
21 decision should be postponed.

1                   Furthermore, a competitive generation market can proceed without compet-  
2                   itive revenue cycle services. Duquesne's proposal promotes an orderly transition  
3                   that minimizes customer confusion. Unbundling the revenue cycle services from  
4                   the existing distribution company structures would require a significant number of  
5                   administrative and procedural details to iron out. Customers have significant  
6                   changes to adapt to without further confusing the issues and potentially affecting  
7                   the service they receive.

8           Q.     Does the Restructuring Legislation require the Commission to unbundle revenue  
9                   cycle services?

10          A.     No, it does not.

11          Q.     Please summarize your conclusions regarding the requirements of the Restructur-  
12                 ing Legislation that apply to revenue cycle services.

13          A.     First, the Legislation states that customer services shall, at a minimum, be main-  
14                 tained at the same level of quality as today, suggesting that no policy should be  
15                 adopted that would degrade service levels. Second, the Legislation recognizes the  
16                 potential customer benefits of installing "enhanced metering capability". Third,  
17                 the unbundling of these services is contemplated, but the Legislation specifically  
18                 indicates that the unbundling of electric utility service charges into generation,  
19                 transmission and distribution charges is the first priority.

20          Q.     Several intervenors have suggested that concerns regarding safety, accuracy,  
21                 installation and performance should be addressed with the assistance of the

1 Commission, through task forces, working groups and generic docket proceedings  
2 (Brown direct at pp. 19-21, Muench direct at p. 12). Do you agree?

3 A. Yes. Furthermore, I believe it would be unwise for the PUC to set a course of  
4 action to unbundle these services in this proceeding until it is known that these  
5 very important issues can be resolved in a manner that maintains existing safety  
6 and consumer protections.

7 Q. Has the Commission established a process to address these and other issues related  
8 to the unbundling of revenue cycle services?

9 A. Yes. The Commission has established working groups in the areas of Metering,  
10 Customer Information and Billing, Reliability, Supplier/Utility/Customer Interac-  
11 tion, Competitive Safeguards, Consumer Education, Retail Access Phase-in,  
12 Universal Service and Conservation, and Taxes to address these issues and to  
13 develop the policies, procedures, standards and implementation requirements  
14 related to the transition to retail competition in Pennsylvania. Stakeholders from  
15 virtually every constituency are represented on these working groups.

16 Q. As contemplated by the Legislation, can retail access be implemented without  
17 unbundling and deregulating revenue cycle services?

18 A. Yes, this is clearly the case. Retail access programs currently in progress in  
19 Pennsylvania and other states support this conclusion.

20 Q. Witnesses Alexander (Direct at p. 41); Brown (Direct at pp. 3-8, 9-10); Muench  
21 (Direct at pp. 5-6); Boonin (Direct at p. 2) and Day (Direct at pp. 3-4) contend that  
22 without unbundling revenue cycle services, suppliers will be unable to attract

1 customers, customers will see fewer benefits, and the market will be less competi-  
2 tive and efficient. They argue this will lead to few market participants as profit  
3 margins in the commodity market for generation decline. Do you agree?

4 A. No. Duquesne shares the Commission's view expressed in the Proposed  
5 Rulemaking that market participants need to first have an opportunity to gain  
6 experience in the primary industry change to competitive generation markets.  
7 Later it may be possible to unbundle other services.

8  
9 **B. If Appropriate Later, Duquesne Will Be Prepared To Unbundle**  
10 **Services**

11  
12 Q. At a future date, following the conclusion of a generic proceeding involving all  
13 Pennsylvania electric distribution companies (EDCs), if ordered by the Commis-  
14 sion, will Duquesne be prepared to unbundle its revenue cycle services?

15 A. Yes. Assuming Duquesne's concerns are addressed by the Commission and the  
16 various stakeholders, Duquesne will unbundle these services from current rates and  
17 give customers that choose alternative providers a credit based on Duquesne's  
18 avoidable service costs.

19 Q. OCA witness Alexander (Direct at p. 42) cites the need for Duquesne's short-term  
20 policies to be compatible with the possibility of increased competition in metering  
21 and metering services. Are Duquesne's current activities compatible with the  
22 possibility of increased competition?

1 A. Yes. Duquesne believes its infrastructure improvements provide benefits in the  
2 short-term and are consistent with the long-term direction of the Commission in its  
3 Proposed Rulemaking.

4 Q. Enron Witness Mr. Brown states that Pennsylvania can implement retail open  
5 access with existing meters (Brown direct at p. 16). Do you agree?

6 A. Yes, but I also believe that Pennsylvania can implement retail open access with  
7 distribution-related meters that are cheaper to operate and more reliable. The  
8 intervenors provide no compelling reason why fair and efficient competition could  
9 not occur if more advanced meters were installed prior to unbundling. If anything,  
10 this should provide more suppliers an opportunity to offer new value-added  
11 services.

12 Q. Witnesses Alexander (Direct at pp.40, 43) and Russell (Direct at pp. 45-46) request  
13 information regarding Duquesne's metering policies. What are Duquesne's  
14 metering policies?

15 A. Consistent with the Proposed Rulemaking, Duquesne will perform all existing  
16 functions related to metering. Duquesne is already well into the process of  
17 installing the Customer Advanced Reliability System (CARS) for customers in its  
18 service area. Customers shall also have the opportunity to choose a Qualified  
19 Advanced Meter to support the generation services provided by their chosen  
20 suppliers. Any alternative meter installed by Duquesne will be billed to the  
21 customer or supplier at net incremental cost as described in the Proposed

1 Rulemaking. Customers who wish to have a second meter installed may do so  
2 subject to the same conditions described above.

3 Q. Does the Proposed Rulemaking specify qualified advanced meter standards?

4 A. No. The Commission states that it is not appropriate to adopt rigid standards for  
5 advanced metering at this time. Instead the regulations are designed to adopt a  
6 flexible set of standards that will be adopted by the Commission from time to time  
7 as requirements based on recommendations of a working Meter Committee. This  
8 Committee is supposed to report to the Commission on or before September 1,  
9 1998 and at least annually thereafter with its considerations and recommendations.  
10 (Proposed Rulemaking pp.15, 17)

11 Q. Does the Commission provide any guidance with respect to defining what consti-  
12 tutes a "Qualified Advanced Meter"?

13 A. Yes. The Commission states that "an advanced meter or network must possess, at  
14 minimum, open, non-proprietary communications capabilities, which allow both a  
15 supplier and EDC to assess the information in a standard data format with multiple  
16 callout capability, unless the Qualified Advanced Meter is to be used in conjunc-  
17 tion with a second meter. In addition, a Qualified Advanced Meter must be  
18 capable of supporting the expected minimum market requirement of hourly usage  
19 and may support one or more other functional requirements such as the ability to :  
20 (1) modify profile intervals; (2) provide a communications port for the customer to  
21 monitor usage; (3) provide a pulse output to allow for usage monitoring; (4)

1 provide password protection; and (5) operate in two directions for net metering."

2 (Proposed Rulemaking, pp. 17-18)

3 Q. Do you expect the CARS system to be able to meet those minimum requirements?

4 A. Yes.

5 Q. Several intervenors have expressed concerns that the CARS system may somehow  
6 be anti-competitive. Does the Proposed Rulemaking support that conclusion?

7 A. No, not at all. In fact, the Commission states that it encourages the integration of  
8 new technologies into the marketplace and wants to monitor the trends. (Proposed  
9 Rulemaking, p.14) I explain the benefits of CARS and address the intervenors'  
10 concerns further in the next section of my testimony.

11

12 **C. CARS Will Provide Better Distribution Service At Lower Cost And Is**  
13 **Pro Customer Choice**

14

15 Q. Please briefly summarize this section of your testimony related to the installation  
16 of CARS.

17 A. Approximately eleven months before the "Electricity Generation Customer Choice  
18 and Competition Act" was signed into law, Duquesne signed a fifteen year, full  
19 service contract with Itron, Inc. to install, operate and maintain its CARS system.  
20 This system is already in the process of installation and will make a significant  
21 improvement in infrastructure to improve and enhance distribution services.

22 The CARS system will provide numerous benefits both to customers and  
23 retail suppliers. First, the installation of CARS will improve system reliability,  
24 provide advanced electronic metering capabilities, improve the use of distribution

1 system assets and provide enhanced information about customer usage. CARS  
2 will enable Duquesne to provide better distribution service (particularly in the  
3 areas of improved reliability and meter reading) at lower cost than it would have  
4 without these improvements. These benefits will accrue to customers that choose  
5 alternative suppliers as well as elect to stay with Duquesne.

6 Second, the CARS Project is pro customer choice. CARS will support a  
7 more reliable and accurate supplier settlement process than other programs based  
8 on estimated load profiles. CARS will allow retail suppliers serving customers in  
9 Duquesne's service area to offer new value-added services to their customers  
10 (time-of-use pricing, real-time pricing, and group consolidated consumption  
11 metering, etc.). Duquesne will make available optional services to competitive  
12 suppliers and/or customers in a non-discriminatory manner consistent with open  
13 access codes of conduct. These optional services will be cost-based and Duquesne  
14 will submit tariffs for these services to the Commission for approval. Finally, the  
15 CARS system does not preclude the unbundling of billing or other services in the  
16 future. Duquesne plans to modify CARS as appropriate to meet the standards  
17 described in the Proposed Rulemaking.

18 Q. Has the Commission reviewed the CARS project prior to this proceeding?

19 A. Yes. Duquesne reviewed this project with representatives of the Commission and  
20 sought temporary relief from certain watt-hour meter testing standards and actual  
21 meter reading requirements. Duquesne not only was granted the requested relief,  
22 the Commission, in correspondence dated February 27, 1996, indicated that, "We

1 are extremely pleased that your company has decided to install an automatic meter  
2 reading system". See Exhibit FRA-5.

3 Q. What is the current status of the CARS implementation?

4 A. Field installation of meters with encoder receiver transmitters (ERTs) has been  
5 completed. Approximately 550,000 ERTs have been installed. The majority of  
6 the fixed network has been installed and communication links have been estab-  
7 lished to read over 123,000 meters from the fixed network. In addition, approxi-  
8 mately 350,000 accounts are being read monthly through use of the van. The  
9 system should be fully operational by December 31, 1998.

10 Q. Witness Brown in his testimony (p. 12) does not agree that there are considerable  
11 benefits to customers by implementing the Itron system. What are the distribution-  
12 related benefits of installing the CARS system for Duquesne and its customers?

13 A. The CARS system provides improved basic operation of the distribution system,  
14 enhances the operation of the distribution system, improves reliability of the  
15 distribution system and finally supports the introduction of customer choice.  
16 Distribution system efficiency and operational information will be extracted from  
17 the CARS system and utilized to reduce the risk of outages due to circuit loading,  
18 improve the planning for distribution expenditures, allow efficient loading and  
19 operation of the system and allow the system operators in general to enhance  
20 system operation. The Commission expects customer service to remain at the  
21 level prior to the introduction of competition and expects it to improve. The

1 CARS system is an integral part of the Company's capability for maintaining and  
2 improving distribution services.

3 In addition to distribution system enhancements, the CARS system will  
4 allow Duquesne to offer: 1) improved load profiles for suppliers and for balancing;  
5 2) improved billing choices for customers; and 3) easier and more friendly service  
6 connection through remote access to the device.

7 In summary, CARS provides operational benefits to the functioning and  
8 efficiency of the distribution system itself and offers customers better service. The  
9 CARS system is integral to the continued improvement in distribution services to  
10 our customers.

11 A list of the specific benefits of the CARS system by function is provided  
12 below:

- 13 • System Reliability
  - 14 ◇ Outage Notification and Restoration Functions
  - 15 ◇ Tamper Monitoring and Reporting Functions
  - 16 ◇ Service Voltage Test
  - 17 ◇ Service Current Test
  - 18 ◇ Power Quality
  - 19 ◇ Diagnostics
  - 20 ◇ System Load Control
- 21
- 22 • Improved Utilization of Distribution Assets
  - 23 ◇ Extended Transformer Life
  - 24 ◇ Power Outage Management
  - 25 ◇ Load Research
  - 26 ◇ System Load Control
- 27
- 28 • System Advanced Electronic Metering Capabilities
  - 29 ◇ System Service Tests
  - 30 ◇ Instrumentation
  - 31 ◇ Power Quality Monitoring Functions

- 1 • New Business Processes
- 2     ◇ New Service Diagnostics
- 3     ◇ Instrumentation Readings
- 4     ◇ Power Quality Diagnostics
- 5
- 6 • Customer Service Benefits
- 7     ◇ Consumption Meter Reading
- 8     ◇ Turn Off/On and Dual Service Orders
- 9     ◇ Group Summary Billing
- 10    ◇ Internet Access to Data
- 11    ◇ Energy Management
- 12    ◇ Daily Read Functions
- 13    ◇ Virtual Disconnect Usage Alarms
- 14    ◇ Billing Cycle Selection
- 15    ◇ Eliminates Inside Customer Access and Property Damage
- 16

17                   Many of the services listed above would be provided to customers at no  
18 charge, while optional services would be available to customers and retail suppli-  
19 ers under open access tariff rates to be filed with the Commission. For an ex-  
20 panded description of these benefits, see Exhibit FRA-6.

21 Q. Do the projected financial benefits for the distribution system exceed their cost?

22 A. Yes. Projected financial benefits for improved reliability and the advanced meter  
23 reading features of CARS exceed their cost. These benefits will result in lower  
24 distribution costs. Exhibit FRA-7 summarizes the cost effectiveness of the CARS  
25 system for Duquesne. Referring specifically to page 5 of this exhibit, the projected  
26 savings from improved base operations, enhanced operations and improved  
27 reliability of the distribution system, absent customer choice benefits, more than

1 offset the cost for installation of the CARS system. For an overview of the  
2 cost/benefit analysis, see Exhibit FRA-7.

3 Q. Have Duquesne's meter reading costs been reduced as a result of the implementa-  
4 tion of CARS?

5 A. Yes. The CARS system was partially implemented in 1996. As a result, the cost  
6 of meter reading declined from 1995.

7 Q. OCA witness Alexander and other intervenors suggest that Duquesne's sharehold-  
8 ers, not ratepayers, should assume the risk of CARS. (Alexander direct at p. 42)  
9 Please explain how Duquesne will recover the costs of CARS.

10 A. The Duquesne contract with Itron is a service agreement that requires Itron to  
11 acquire, install and maintain the metering and other facilities necessary to support  
12 the automated information network. Duquesne will incur no capital costs to  
13 implement CARS. The costs of the service agreement for each year and over the  
14 fifteen year term are offset by cost reductions associated with base operations,  
15 improved reliability, enhanced base services, and customer choice. This means  
16 that the cost of providing distribution service will be lower than it would have been  
17 without CARS. This is a source of cost mitigation, not unlike other cost-cutting  
18 measures, and will allow Duquesne to amortize its stranded costs more quickly, as  
19 described in Mr. Clayton's testimony. Thus, it is irresponsible and unfair for these  
20 parties to claim that this lower level of costs should be disallowed from rates.

1 Q. OCA witness Alexander asserts that CARS will provide a big marketing advantage  
2 to Duquesne since the reliability benefits are not shared by other suppliers (Alex-  
3 ander direct at pp. 40-41). Is this true?

4 A. No. As stated earlier, Duquesne will provide retail suppliers equal access to the  
5 service offerings of the CARS system in a non-discriminatory manner. Moreover,  
6 the reliability benefits that I discussed earlier relate to distribution service, not the  
7 supply of generation. Finally, the issues raised regarding accessibility to the  
8 CARS system information by witnesses Alexander and Brown (Direct at pp. 12-  
9 14) should be resolved through the qualification process. As described in witness  
10 Brown's "Non-Wire Communications Network Conceptual Model", (Exhibit JAB-  
11 4), standards and protocols have not been developed for two of the three communi-  
12 cation areas addressed. Duquesne agrees with the Commission that the Metering  
13 Committee is the proper vehicle to resolve these issues.

14 Q. Does CARS facilitate or hinder retail choice of alternative suppliers?

15 A. CARS will provide several benefits to promote fair and efficient retail choice. The  
16 load profiling capabilities of CARS will allow Duquesne to compute the aggregate  
17 hourly consumption for each supplier's customer more accurately than by using  
18 historical load profiles based on sample interval reading data to develop estimates  
19 of consumption. These load profiles are essential to the supplier settlement  
20 process. This certainly is an important component of providing retail access. All

1 parties should have more comfort in knowing that actual customer consumption  
2 can be measured as opposed to being estimated.

3 Q. Please describe some of the other capabilities of CARS that may be available to  
4 customers or retail suppliers other than those already detailed?

5 A. Over time, the capabilities of CARS will be increased to provide suppliers and/or  
6 customers with new products and services. With more information available about  
7 individual customer use, flexible rates can be tailored to provide new value-added  
8 services. The ability of CARS to process information about energy usage will  
9 provide customers or their suppliers new choices and greater convenience. For  
10 example, customers would be able to select which day of the month to pay their  
11 bills. CARS will permit development of a daily profile of the electricity usage of  
12 each customer. CARS can provide Duquesne's customers or suppliers with a wide  
13 variety of advanced metering capabilities:

- 14 • Daily scheduled consumption meter readings
- 15 • On-request readings
- 16 • Flexible start and end-of-service readings
- 17 • Flexible time-of-use rates
- 18 • Load profile information
- 19 • Energy Management Opportunities

20  
21 Q. Will the distribution system benefits of CARS and these other capabilities, such as  
22 those that facilitate customer choice, be accessible to competitive suppliers?

- 1           A.     Yes. Consistent with the Proposed Rulemaking, Duquesne and Itron will work  
2                     with the Metering Committee to qualify the CARS system to meet Sections 57.252  
3                     and 57.253 of the Proposed Rulemaking.
- 4           Q.     Some features of the CARS System described in the CARS Financial Analysis  
5                     Report refer to marketing benefits. Please comment.
- 6           A.     As discussed previously, Duquesne plans to qualify the CARS system as a  
7                     Qualified Advanced Metering network consistent with the Proposed Rulemaking.  
8                     By doing so, customers and suppliers will have equal access to, and choice of, the  
9                     capabilities of the CARS system. Suppliers will not be disadvantaged because  
10                    Duquesne affiliates will be treated comparably to non-affiliates in accessing the  
11                    CARS system.
- 12          Q.     Please provide examples of fees charged by Itron, Inc. to Duquesne for some of  
13                     these optional services?
- 14          A.     As indicated in Exhibit FRA-7, Itron, Inc. will assess Duquesne optional charges  
15                     for the use of demand (kW) reads (\$0.20 per meter per month), time-of-use (TOU)  
16                     metering reads (\$0.30 per meter per month), real-time pricing reads (\$0.50 per  
17                     meter per month) and load profile reads (\$2.75 per meter per month). In addition to  
18                     these out-of-pocket costs, Duquesne will include any other net incremental costs in  
19                     its tariff for these services to be billed to those customers or suppliers who choose  
20                     to use them.

- 1 Q. Enron witness Muench states that Duquesne charges should be "cost based",  
2 "reasonable" and with "Commission oversight" (Direct at p. 15). Does Duquesne  
3 agree?
- 4 A. Yes. I also note that many of the distribution-related services will be provided to  
5 customers at no additional cost, given that Duquesne expects distribution-related  
6 costs to be lower than what they would have been without these improvements. In  
7 any event, the Proposed Rulemaking allows Duquesne to assess the net incremen-  
8 tal cost it incurs as a result of the use of Qualified Advanced Meters in its network.  
9 A customer surcharge or supplier payment for optional value-added services will  
10 be filed by Duquesne and subject to Commission review consistent with the  
11 Proposed Rulemaking.
- 12 Q. OCA witness Alexander assumes that Duquesne will not charge other fees related  
13 to implementing customer choice since no mention of them was made in my direct  
14 testimony. (Alexander direct at p. 44) Is that correct?
- 15 A. No. The Restructuring Legislation allows the Company to recover such transition  
16 costs. Duquesne will establish cost-based charges and file them with the Commis-  
17 sion for their approval. These costs could potentially be recovered in user fees  
18 and/or as a transition cost regulatory asset.
- 19 Q. What related retail choice services does Duquesne plan to provide and at what  
20 cost?

1           A.     Duquesne will charge customers and/or suppliers the net incremental cost of  
2           providing the following services:

- 3           •     Changing Customer's Electric Supplier of Record (except for the first  
4           change)
- 5           •     Supplier Settlement
- 6           •     Customized Billing
- 7           •     Collection Activities
- 8           •     Customer Payment Processing
- 9           •     Customer Service
- 10          •     Others (as they are identified)

11  
12                     It is impossible at this time to know with certainty all the direct transition  
13           costs associated with implementing retail choice. Duquesne will continue to  
14           monitor this process and will develop and file cost-based charges for Commission  
15           approval as deemed necessary.

16  
17           **D.     Other Issues Regarding Unbundling**

18  
19          Q.     OCA witness Alexander states that Duquesne should be required to describe how it  
20           would comply with three billing options. (Alexander direct at p. 44) What is  
21           Duquesne's position regarding the three billing options addressed by the Commis-  
22           sion in its final order regarding Guidelines for Maintaining Customer Services at  
23           the Same Level of Quality (Folder 11 Order)?

1 A. The three billing options allow a retail customer to choose among the following:

- 2 • Receive a single bill from Duquesne for both its charges and supplier
- 3 charges.
- 4 • Receive two bills -- one for services from Duquesne and one for services
- 5 from the alternative supplier.
- 6 • Receive a single bill from a supplier for both its charges and those of
- 7 Duquesne.

8  
9 Duquesne supports the first two billing options as mandated by Section  
10 2807(C) of the Restructuring Legislation and affirmed by the Commission in the  
11 Folder 11 Order (p. 11).

12 Q. Witnesses Alexander (Direct at pp. 44-45); Russell (Direct at pp. 42-45); Brown  
13 (Direct at p. 18); Muench (Direct at pp. 4, 7-8); Boonin (Direct at p. 21); and Day  
14 (Direct at pp. 4-5) support the third billing option, "supplier complete billing", to  
15 allow suppliers to provide more comprehensive and value added services and to  
16 enhance profitability when commodity prices yield thin profit margins. Why  
17 doesn't Duquesne also support this option?

18 A. Duquesne's concerns center around its experience in the Customer Choice Pilot  
19 Program. First, six of the seventeen suppliers participating in the Pilot are requir-  
20 ing their customers to adopt the two-bill billing option, contrary to Mr. Muench's  
21 testimony (Direct at p.9). Second, at least one supplier has implemented a cancel-  
22 lation fee to its residential customers, a clear disincentive to return to Duquesne.  
23 Third, the exchange of information with suppliers by electronic media during the  
24 Pilot has been somewhat problematic. For these reasons, Duquesne believes this

1 issue should be addressed by a working group within a generic rulemaking  
2 proceeding.

3 Q. Witness Muench (Direct at p. 13) broaches the issue of allowing a supplier to act  
4 in an agency capacity with respect to billing and collection. What is Duquesne's  
5 position regarding this proposal?

6 A. Duquesne believes the following points are significant:

- 7 • Only the EDC, Duquesne, can provide metering services for customers.
- 8 • Only the EDC, Duquesne, can physically disconnect service.
- 9 • The Commission requires the EDC's service representatives to determine  
10 whether the customer is requesting discontinuance of *service* at their  
11 current location, or discontinuance of *supply* from their current supplier.
- 12 • The single supplier bill option has not been endorsed by the Commission.  
13 Given the above, Duquesne does not see the benefits to the customer of  
14 modifying its tariffs to allow suppliers to act in an agency capacity.

15 Q. Enron witness Muench (Direct at p. 3) addresses the need to provide adequate  
16 information to determine the basis for all of the various charges included in the  
17 EDC's bill in an understandable format. What is Duquesne's position regarding  
18 the information to be presented on the customer's bill?

19 A. Duquesne, like Enron, takes pride in its billing and customer service activities and  
20 strives to provide its customers with the highest quality billing services possible.  
21 Duquesne was one of the first utilities to implement a customer guarantee pro-

1 gram. However, the Commission has been very clear in section 56.15 of Chapter  
2 56 and in the proposed rulemaking order regarding Customer Information Disclo-  
3 sure for Electricity Providers as to the information content of bills for residential  
4 and small commercial customers. At issue here is the definition of non-basic  
5 services. Duquesne proposes that the appropriate working group(s) address this  
6 issue. The unbundling of charges and their presentation on the billing statement  
7 proposed by witnesses Alexander (Direct at p. 42) and Muench (Direct at p. 3-4)  
8 have not been ordered by the Commission in any of its rulemakings.

9 Q. Does Duquesne plan to restrict the types of charges or rate design supported by its  
10 billing system?

11 A. In the Customer Choice Pilot Program currently in progress, Duquesne has been  
12 able to accommodate all of the rate schedules proposed by suppliers to prepare  
13 consolidated bills. Based on this experience, it appears that the concerns of OCA  
14 witness Alexander (p. 45) in this regard may not be an issue. Also, the CARS  
15 system may enable suppliers to offer new pricing options and any customized  
16 billing options offered by Duquesne would be cost-based.

17  
18 **III. Application of Customer Payments**

19 Q. OCA witness Alexander (Direct at pp. 45-46) expresses concerns about  
20 Duquesne's proposed application of partial payments when Duquesne renders a  
21 single consolidated bill. How does Duquesne plan to apply customer payments?

1           A.     Duquesne will maintain accounts receivable balances (Alexander direct p. 45) and  
2                     apply customer payments in the consolidated bill scenario consistent with the  
3                     Guidelines for Maintaining Customer Services at the Same Level of Quality  
4                     (Folder II Order). These Guidelines are set forth below:

5                     For a customer who has a pre-retail access balance, the payment should be  
6                     applied by the EDC as follows: (1) outstanding pre-retail access balance or the  
7                     installment amount for a payment agreement on this balance; (2) intangible  
8                     transition charge (ITC) and competitive transition charge (CTC); (3) EDC trans-  
9                     mission and distribution charges (T&D); (4) supply charges, and (5) non-basic  
10                    service charges. If the customer's account develops a post-retail access balance,  
11                    partial payments should be applied to the pre-retail access balance, according to  
12                    the terms of the pre-retail access payment agreement, before being applied to any  
13                    other outstanding post-retail access charges. For a customer with no pre-retail  
14                    access balance but with a post-retail access balance, partial payments should be  
15                    applied as follows: (1) balance due for prior ITC, CTC, and T&D service; (2) ITC  
16                    and CTC; (3) T&D; (4) balance due for prior supply charges; (5) supply charges,  
17                    and (6) non-basic service charges.

18           Q.     Enron witness Muench (Direct at pp. 17-19) does not agree with the proposed  
19                    method of applying payments proposed by Duquesne. Please explain Duquesne's  
20                    position.

1 A. Duquesne has modified its proposed method of application of customer payments  
2 to comply with the Folder II Order. The issues raised by Muench have been, for  
3 the most part, addressed by the Commission in the rulemaking.  
4

5 **IV. Customer Service Procedures**

6 Q. OCA witness Alexander expresses concerns regarding complaint resolution (Direct  
7 at p. 46), service interruptions and outages (Direct at p. 47), requests to discontinue  
8 service by customer (Direct at p. 48) and termination and payment agreements  
9 (Direct at p. 48). What is the position of Duquesne with respect to these issues?

10 A. First, Duquesne's procedures will be consistent with the Commission guidelines,  
11 rules and regulations. Second, these procedures are being developed and will be  
12 implemented during the Customer Choice Pilot Program. Attached as Exhibit  
13 FRA-8 is the most recent release of Duquesne's procedures for customers and  
14 suppliers during the Customer Choice Pilot Program. These procedures will be  
15 revised as appropriate based on Duquesne's experience during the Pilot Program.

16 Q. OCA witness Alexander (Direct at p. 44) addresses the use of standard load  
17 profiles and the need for these profiles to be updated frequently and approved by  
18 the Commission. What is Duquesne's position?

19 A. Duquesne has provided historical hourly load profiles for each rate class, hourly  
20 average temperature data and hourly humidity data to suppliers for scheduling  
21 purposes during the Customer Choice Pilot Program. As described previously,

1 Duquesne plans to make the load profile information from the CARS system,  
2 based first on daily, and then hourly readings, available to customers and suppliers.  
3 This information will be updated frequently and should not require Commission  
4 approval since it will be based on actual, and not estimated, metering information.  
5

6 **V. Conclusions**

7 Q. What do you conclude?

8 A. I have five major conclusions:

- 9
- 10 • First, the Commission should postpone the decision whether or not to  
11 unbundle revenue cycle services since (a) numerous issues need to be  
12 resolved first in order to maintain the integrity of the system, (b) the  
13 Commission has already established a process to address these issues in a  
14 generic proceeding, and (c) it is not required to meet the primary objective  
15 of the Restructuring Legislation to develop competitive generation markets.
  - 16 • Second, if at some later date, the various parties are able to adequately  
17 address the concerns associated with unbundling certain services,  
18 Duquesne is prepared to do so.
  - 19 • Third, the CARS system will provide better distribution service at lower  
20 cost and will promote, not hinder, customer choice.
  - 21 • Fourth, Duquesne will apply customer payments consistent with the Folder  
II Order for the consolidated billing scenario.

1                   •     Fifth, Duquesne will use the Customer Choice Pilot Program to develop  
2                             and implement customer service procedures to meet Commission guide-  
3                             lines and rulemakings by January 1, 1999.

4           Q.     Does this conclude your testimony?

5           A.     Yes.

- 1 Exhibit FRA-5 - Letter from the Commission
- 2 Exhibit FRA-6 - Distribution System Benefits
- 3 Exhibit FRA-7 - Customer Advanced Reliability System Cost/Benefit Analysis
- 4 Exhibit FRA-8 - Customer Choice Pilot Customer and Supplier Procedures



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

February 27, 1996

2-29-96

Exhibit FRA-

Page 1 of 1

IN REPLY PLEASE  
REFER TO OUR FILE

F.M. Nadolny, General Manager  
Regulatory Affairs Unit  
Duquesne Light  
411 Seventh Avenue  
P.O. Box 1930  
Pittsburgh, PA 15230-1930

*Frank*

Dear Mr. Nadolny:

Thank you for your recent visit to Harrisburg to discuss your company's request for waiver of our regulations with regard to your meters. Our discussions have been productive and have cleared up all questions regarding what Duquesne intends to do over the next two-year period. We are extremely pleased that your company has decided to install an automatic, meter-reading system.

Accordingly, your request for waiver of 52 Pa. Code §57.20 and §56.12 is granted for a two-year period beginning April 1996. During this period, you should submit annual reports to the Bureau of Transportation and Safety detailing your experience with the new system. The information that you should provide on an annual basis is set forth in your February 14, 1996, letter to me.

At the expiration of the waiver period, it is recommended that you formally request a waiver from the Commission. For your use and information, enclosed is a copy of an order which grants similar relief to PECO Energy Company.

If you have any questions or concerns regarding this matter, we can address those during my visit to Pittsburgh on March 7, 1996. Thanks again for your prompt response to our concerns regarding your request.

Very truly yours,

*Ken*

Kenneth E. Nicely, Director  
Bureau of Transportation and Safety

KEN:rjm

pc: Jerry Wells, Standardization Lab

**DUQUESNE LIGHT COMPANY**  
**Customer Advanced Reliability System**

**DISTRIBUTION SYSTEM BENEFITS**

---

Installation of the CARS system will bring about many distribution system benefits when the network is fully installed.

**I. SYSTEM RELIABILITY**

***Outage Notification and Restoration Functions***

CARS outage detection capabilities will provide reliable analysis and reporting benefits for power outage conditions. The system's power restoration verification capabilities will help identify secondary (downstream) outages and eliminate customer call-backs. The CARS system provides a capability to identify which customers have lost electric power. For decades, utilities have relied on customer phone calls to know when and where an outage occurred and whether power was restored. The CARS system provides the required information without relying on phone calls or customer interaction.

The CARS system uses the distributed intelligence of the system's neighborhood Cell Control Units (CCU) to gather and report outage notification. When a CCU loses AC power, it will report this condition to Duquesne Light's Operations Center (DOC). Once in the DOC database, outage information is available and can be transferred to other applications such as a trouble call. This provides a positive and recorded verification that an outage condition exists.

When power is restored to an area, the CCU immediately senses the presence of AC power. Meter modules formerly without power also respond to polls by the CCU and send appropriate information to the DOC. This provides positive confirmation that an outage condition has been corrected. Positive verification of power restoration provides very important benefits. For example, repair crews will no longer leave an area assuming the outage was corrected only to find out later that there was another nearby outage (e.g. blown line fuses). What's more, the need for customer call-backs is reduced, which is especially beneficial for outages corrected at night.

The CARS system will be integrated with other outage management systems and Geographic Information Systems (computerized mapping) to provide a pictorial view of outage areas. Telephone-based trouble reports can be combined with CARS outage information to provide a complete picture of the outage, and accelerate restoration efforts.

Since CARS data and control structures are stored in one of several Duquesne Light relational databases, full access to the data can be obtained for any distribution application capable of data access. This will allow Duquesne Light to create additional applications in the future.

Key benefits to the distribution company are the rapid response to power outages, reduced repair costs by dispatching the line crew to the right location and verifying that the entire outage has been corrected, thereby avoiding redispach of the crew to the same area later. Reduced customer service costs could also be experienced by reducing trouble call frequency and outage duration which helps to improve customer satisfaction. It also allows for a standard database format for interface with other related applications, such as SCADA.

Customers will benefit from shorter outages due to the improved response time and verification that an outage has been corrected. Quicker, more accurate responses to trouble calls and outage detection and correction verification, even when customer is not at home, will greatly improve customer satisfaction.

### ***Tamper Monitoring and Reporting Functions***

CARS tamper monitoring and reporting functions will provide remote meter tamper monitoring and reporting of all meters connected to the Duquesne Light system. Losses due to theft will be minimized, as system alarms provide the distribution company with the ability to quickly respond to theft conditions.

The CARS tamper monitoring and reporting features eliminate much of the burden of theft investigation by providing new capabilities and benefits that are otherwise too costly and inefficient. Any meter connected to the Duquesne Light system will monitor and report tampers. Immediate notification when a tamper occurs will result in the identification of theft and bring about a reduction in losses. The CARS system will provide complete information by automatically generating a daily report of all accounts showing any changes in tamper status. Any meter showing a tamper status can be isolated and Duquesne Light can then view information on the account. The Duquesne Light user interface will show account and meter module information as well as a log of past meter readings. In addition, any suspect account can be selected and viewed for tamper activity.

Each meter module has a built-in tamper indicator. For electric meters, the system monitors meter tilt and removal tampers. When a tamper occurs, the tamper counter on the meter is activated. Each time the meter is read by the fixed network, the tamper count is transmitted. If the current tamper count differs from the tamper count obtained on the previous read, a tamper is reported.

A specific account could be more closely monitored by the distribution company by initiating a specific read interval. Each time the selected meter is read and a tamper is identified, a tamper alarm would be reported. Any meter in the system can be monitored and reported, and changes can be monitored remotely from utility headquarters. The tamper monitoring interval could be set for a particular time period by establishing start and stop dates and times and monitoring interval times.

Important benefits to the distribution company are the reduced costs associated with theft investigation, elimination of liability and risk associated with on-site investigations, and the immediate identification of theft and resulting avoided losses. Remote monitoring capability and a log of the tamper history can provide proof of theft. Any meter can be monitored, and Duquesne Light's system will provide reporting capabilities on any account including status, history and exception reporting.

Improved ability to analyze theft losses will also aid the distribution company in the evaluation of system line losses which will bring about an improvement in overall distribution system integrity.

## II. IMPROVED UTILIZATION OF DISTRIBUTION ASSETS

The DOC and System Planning will be able to improve line inefficiencies and better balance loads through utilization of CARS system capabilities. Presently, System Operations has limited telemetering information beyond the substation. Telemetry data from individual customers' meter points provides information that will help optimize circuit regulation and balance. This optimization process should result in lower energy loss expenses.

CARS will provide an information based data platform permitting the distribution company to incrementally add power system capacity. Additions or changes could be made one customer at a time through utilization of demand control processes during peak periods. Market and customer incentives can be developed to encourage customer participation in load shifting programs. However, if the necessary infrastructure is not in place, customer participation is irrelevant. Hence, CARS and its data communications platform is expected to become a valuable component of Duquesne Light's ability to provide strategic energy shaping management programs.

An important system planning benefit of CARS supported load management capability is the potential to better manage significant capital expenditures. Several power distribution plant areas within Duquesne Light's service territory are meeting or exceeding their capacity limits. Utilizing CARS obtained customer usage profiles, Duquesne can better forecast loading, plan capacity additions, and provide market incentives for strategic load shaping to minimize the need for capacity additions. The new distribution company's business planning process can optimize utilization of existing assets with information gathered from CARS. Significant annual capital expenses for distribution transformer replacements may be averted through application of CARS information.

The bulk of transformer failures are due to repeated overloads. If CARS is used to analyze and proactively manage transformer replacements prior to failure, a majority of overload failures could be averted. This means that transformers can be replaced, when necessary, on a straight-time basis and need not be repaired since they have not failed. Not incidentally, a significant number of unplanned customer outages will be avoided annually.

**Extended Transformer Life** - Transformer life will be extended. In addition to severe overload failures, this type of proactive distribution plant management will minimize overloading. Any overloading shortens the life of the transformers. Fewer failed transformers will be reworked in Duquesne's shops. Many transformers are repaired in the shop annually. Less labor will be required since this number would be greatly reduced.

**Power Outage Management** - Annual system disturbances cause lost revenue due to unplanned outages of this type. Minimizing outages due to failed distribution transformers, along with quicker restoration through improved outage information should reduce annual lost revenue significantly.

**Load Research** - Currently, there are approximately 300 load research meters manually read by field meter service technicians. CARS will provide access to these and many more meters automatically to greatly enhance the distribution company's load research capabilities, while eliminating the manual reading efforts.

**System Load Control** - Duquesne experiences a needle peak of about 400 megawatts during summer months. This requires a potential reserve of 400 megawatts to supply an air conditioning load that is only needed for approximately one percent of the total time in a year. CARS will provide an information platform that supports the distribution company's ability to incrementally improve power system capacity load factor through customer demand control, on an as-needed basis as customer demand versus system capacity tightens.

### III. SYSTEM ADVANCED ELECTRONIC METERING CAPABILITIES

Through the CARS project, new automated functionality will be available to enhance service reliability to Duquesne's customers. This higher level of service reliability was not possible prior to the installation of new advanced electronic meters. Features of new electronic meter technology that contribute to increased service reliability include system service tests, instrumentation and power quality monitoring.

**System Service Tests** - System service tests are performed to check the validity of the electrical service as wired to the meter. Advanced electronic meters can verify the service type, phase rotation and validity of phase voltages; it also determines whether the phase currents are reasonable.

**Service Voltage Test** helps to locate misapplied or incorrectly wired voltage transformers and aids identification of open or missing line-side fuses.

**Service Current Test** - A test of the service current can also be scheduled. When current on any phase falls above or below the programmed limit, when current is negative or missing on any phase, or when the power factor is outside the preset limit, the meter will provide a service error code.

**Instrumentation** - Instrumentation provides instantaneous displays of metering values which will enable Duquesne Light to analyze the customers' electrical service at the moment of delivery. Service instrumentation and power monitoring information will provide Duquesne Light with the unique capability of performing site diagnostics and service checks locally at the customer site and remotely using data collection capabilities of the CARS system.

**Power Quality** - Advanced electronic meters can monitor circuit parameters on a cyclical basis, 24 hours per day. With system power quality monitors (PQM) advanced electronic meters can monitor voltage, current and total harmonic distortion (THD) for variations outside pre-selected threshold limits. Every time conditions fall beyond these parameters in 1, 2 or all 3 phases, the incident will be noted in an event counter and an event timer. Separate event counters and timers are available for each of ten power quality monitors. Event counters keep a cumulative count of how many times each parameter was exceeded; event timers give the total elapsed time for each parameter.

For further study of power quality issues, an advanced electronic meter can record a date and time stamp when any of the monitored quantities exceed a programmed threshold, and again when the event returns to normal conditions.

**Momentary Voltage Sag** - One power quality monitor that will significantly benefit customer service reliability is date/time stamp of momentary voltage sag. Since voltage sag may be a reduction in voltage for only a few line cycles, the advanced electronic meter monitors each phase voltage on a continual basis, measuring the rms voltage every two line cycles. This permits the recognition and recording of events occurring when the voltage drops below a specified threshold for two cycles or longer. A maximum time duration provides a dividing line between short duration sags and longer term low voltage conditions.

Advanced data collection and analysis tools provided by CARS enable dynamic graphic interpretations and display of power quality and power measurement data obtained through end point devices located at customer premises served by the distribution company. The chart of advanced electronic metering capabilities identifies the features that are integrated into the CARS system. In addition to consumption information needed for revenue billing, the electronic meter and end point devices provide timely access to critical information needed by the distribution system to meet customer expectations for reliable service in a competitive energy market.

**ADVANCED ELECTRONIC METER CAPABILITIES**

FEATURES	CUSTOMER SERVICE	RELIABILITY OF SERVICE
<ul style="list-style-type: none"> <li>• Instrumentation                             <ul style="list-style-type: none"> <li>- Service Voltage Test</li> <li>- Service Current Test</li> <li>- Per Phase Voltage</li> <li>- Per Phase Current</li> <li>- Per Phase Voltage Phase Angle</li> <li>- Per Phase Current Phase Angle</li> <li>- Per Phase Power Factor</li> <li>- Per Phase Power Factor Angle</li> <li>- Per Phase Watts</li> <li>- Per Phase VARS</li> <li>- Per Phase VA</li> <li>- Per Phase Total Harmonic Distortion for Voltage</li> <li>- Per Phase Total Harmonic Distortion for Current</li> <li>- System Line Frequency</li> <li>- System KW</li> <li>- System KVAR</li> <li>- System KVA</li> </ul> </li> </ul>		<ul style="list-style-type: none"> <li>✓</li> <li>✓</li> <li>✓</li> <li></li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> </ul>

FEATURES	CUSTOMER SERVICE	RELIABILITY OF SERVICE
<ul style="list-style-type: none"> <li>• Power Quality Monitors (Event Counters and Timers)               <ul style="list-style-type: none"> <li>- Momentary Voltage Sag</li> <li>- Service Voltage Test</li> <li>- Low Voltage Test</li> <li>- High Voltage Test</li> <li>- Reverse Power and PF Test</li> <li>- Low Current Test</li> <li>- Abnormal Power Factor</li> <li>- Second Harmonic Test DC</li> <li>- Total Harmonic Distortion for Current</li> <li>- Total Harmonic Distortion for Voltage</li> </ul> </li> </ul>		<ul style="list-style-type: none"> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> </ul>
<ul style="list-style-type: none"> <li>• Power Quality Event Logs               <ul style="list-style-type: none"> <li>- Time/Date of Extended Outages</li> <li>- Time/Date of Test Mode Events</li> <li>- Time/Date of Time Change Events</li> <li>- Time/Date of Demand Resets</li> <li>- Time/Date of Voltage Sags</li> </ul> </li> </ul>		<ul style="list-style-type: none"> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> </ul>
<ul style="list-style-type: none"> <li>• Outage Callback</li> </ul>		<ul style="list-style-type: none"> <li>✓</li> </ul>
<ul style="list-style-type: none"> <li>• Outage Restoration Notification</li> </ul>		<ul style="list-style-type: none"> <li>✓</li> </ul>
<ul style="list-style-type: none"> <li>• Power Quality Output Alarms</li> </ul>		<ul style="list-style-type: none"> <li>✓</li> </ul>
<ul style="list-style-type: none"> <li>• Load Control Relay Outputs (Time and Data)</li> </ul>	<ul style="list-style-type: none"> <li>✓</li> </ul>	
<ul style="list-style-type: none"> <li>• Reverse Energy Flow Warning</li> </ul>		<ul style="list-style-type: none"> <li>✓</li> </ul>
<ul style="list-style-type: none"> <li>• Demand Overload Warning</li> </ul>	<ul style="list-style-type: none"> <li>✓</li> </ul>	<ul style="list-style-type: none"> <li>✓</li> </ul>
<ul style="list-style-type: none"> <li>• Consumption Measurements               <ul style="list-style-type: none"> <li>- Total Real Energy (KWH)</li> <li>- KW Demand</li> <li>- Total KVARH (Quadrants I, II, III and IV)</li> <li>- Total KVAH</li> <li>- Cumulative KW Demand</li> <li>- Load Profile Data Recording</li> <li>- TOU (4 or 5 Rate)                   <ul style="list-style-type: none"> <li>⇒ Cumulative Energy for Each TOU Rate Period</li> <li>⇒ Maximum Demand With Its Date and Time for Each TOU Rate Period</li> <li>⇒ Cumulative Demand for Each TOU Rate Period</li> <li>⇒ Separate Demand Thresholds for Each TOU Rate Period</li> </ul> </li> <li>- Programmable Demand Threshold</li> <li>- Programmable Demand Forgiveness After Power Outage</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> </ul>	<ul style="list-style-type: none"> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> </ul>

FEATURES	CUSTOMER SERVICE	RELIABILITY OF SERVICE
<ul style="list-style-type: none"> <li>- Installation Warning Flags               <ul style="list-style-type: none"> <li>⇒ Voltage Transformer Polarity</li> <li>⇒ Current Transformer Polarity</li> <li>⇒ Service Wiring</li> </ul> </li> <li>- Site Diagnostics</li> <li>- Power Relationship Graphs</li> <li>- Harmonics Graphing Software</li> <li>- Phasor Graphing Software</li> </ul>	<ul style="list-style-type: none"> <li></li> <li></li> <li></li> <li></li> <li>✓</li> <li>✓</li> <li>✓</li> </ul>	<ul style="list-style-type: none"> <li></li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> <li>✓</li> </ul>

#### IV. NEW BUSINESS PROCESSES

CARS implementation will bring about a significant improvement in the distribution company's ability to connect new services to power distribution networks in a timely manner and to cancel old services no longer required by the customer. When linked with the Company's Work Management System, new services will automatically be scheduled for installation of CARS system meter devices and will support the Company's goal of providing new service connections within 48 hours. Once connected to the CARS system, a customer will be able to receive enhanced meter data and other benefits such as timely processing of canceled service and eventually new energy management applications.

##### *New Service Diagnostics*

Customers equipped with advanced metering devices can initially and periodically check the service wiring to make sure it is accurate. This feature increases the quality of electricity service by reducing the potential for installation errors or subsequent tampering situations that could otherwise go undetected.

##### *Instrumentation Readings*

More sophisticated commercial and industrial customers can receive very accurate, key engineering units of the electricity flowing through the wires. This data is useful to both the utility distribution company as well as the customer when setting up new business processes. Today it is not uncommon for industrial customers to pay energy management companies to provide this kind of information.

##### *Power Quality Diagnostics*

Advanced metering power quality diagnostic software can provide key indicators for help in troubleshooting new services with known power quality problems. The software will communicate directly with the meter – either locally or over a modem. This software also provides visual indication of the accuracy of the wiring and meter application at the customer's site.

## V. CUSTOMER SERVICE BENEFITS

Many of the features provided through CARS system implementation will have significant customer satisfaction benefits. Customer service representatives will be able to provide a wide range of information obtained through the distribution company's integrated system network. Once connected to the network, a customer's meter can become a valuable source of information for monitoring energy use and ensuring that power conditions are satisfactory for equipment operated on the distribution network for business or home use. Some applications which will become available through the system that will enhance customer satisfaction are as follows:

- Consumption Meter Reading
- On-Request Reads
- Turn On/Offs and Dual Service Orders
- Group Summary Billing
- Internet Access to Data
- Energy Management
- Daily Read Functions
- Virtual Disconnect Usage Alarms
- Billing Cycle Selection
- Time-of-Use Rates
- Load Profile Information

In addition, the benefits of improved outage detection and restoration described above will also contribute significantly to improved customer satisfaction through a reduction in the number and duration of outages experienced by customers on the Company's distribution lines.

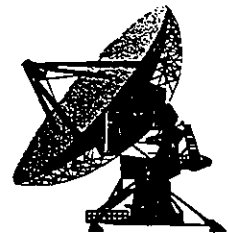


# Customer Advanced Reliability System



## Financial Analysis Report

October 1996



Confidential & Proprietary

# **CUSTOMER ADVANCED RELIABILITY SYSTEM**

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# **CUSTOMER ADVANCED RELIABILITY SYSTEM**

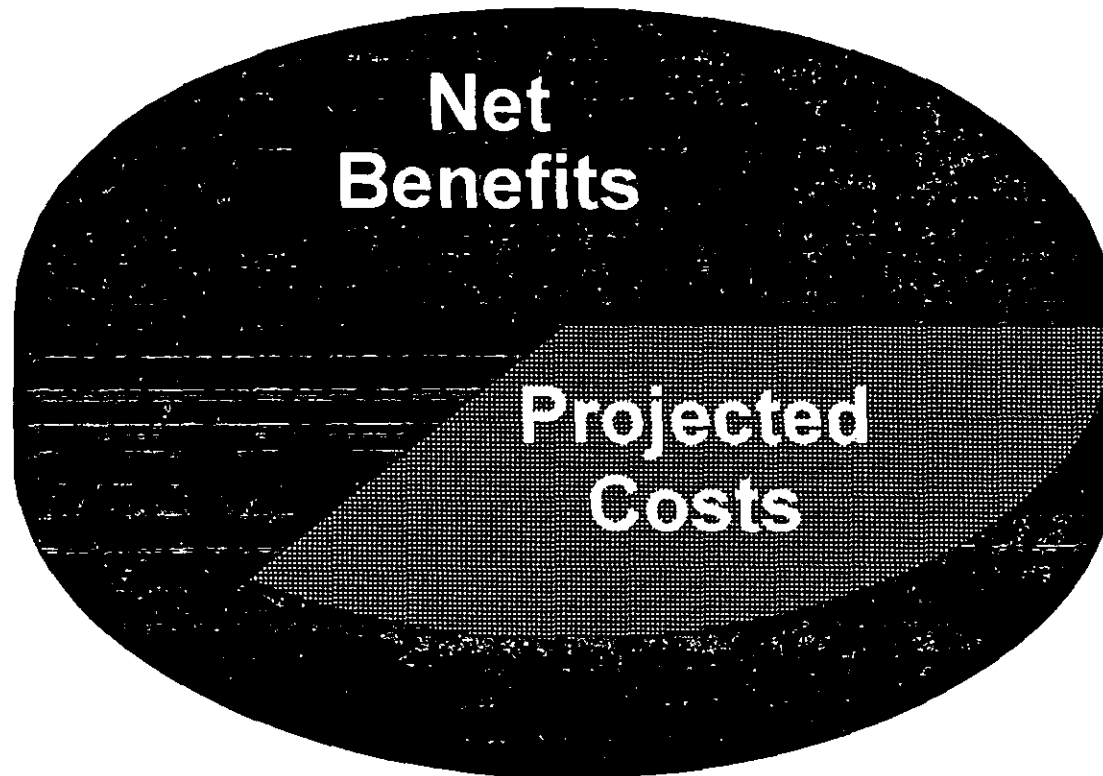
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**OVERVIEW**

# Customer Advanced Reliability System Overview - Cost/Benefit Analysis



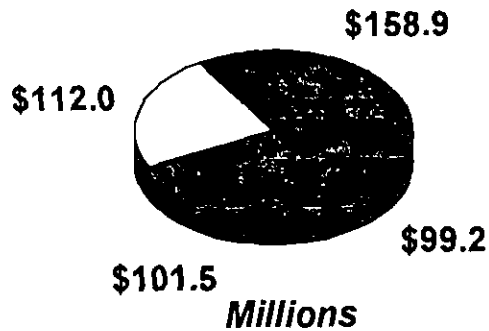
**Total Benefits: \$471.7 Million**

- Customer Choice
- Improved Reliability
- Enhanced Operations
- Base Operations

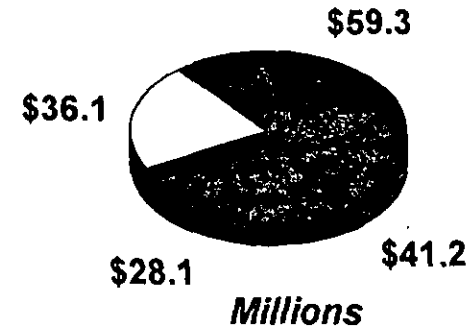
**Projected Costs: \$164.7 Million**

- Itron Services Agreement

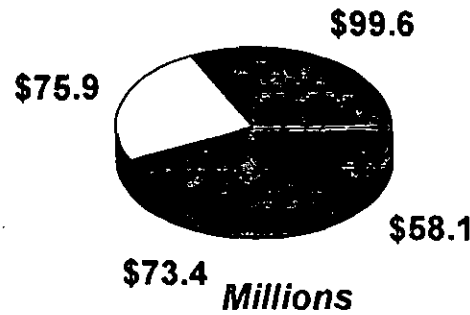
# Customer Advanced Reliability System Overview - Cost/Benefit Breakdown



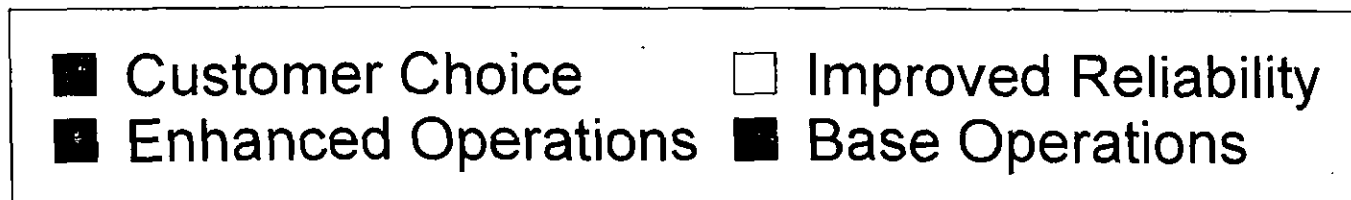
**Total Benefits**



**Projected Costs**

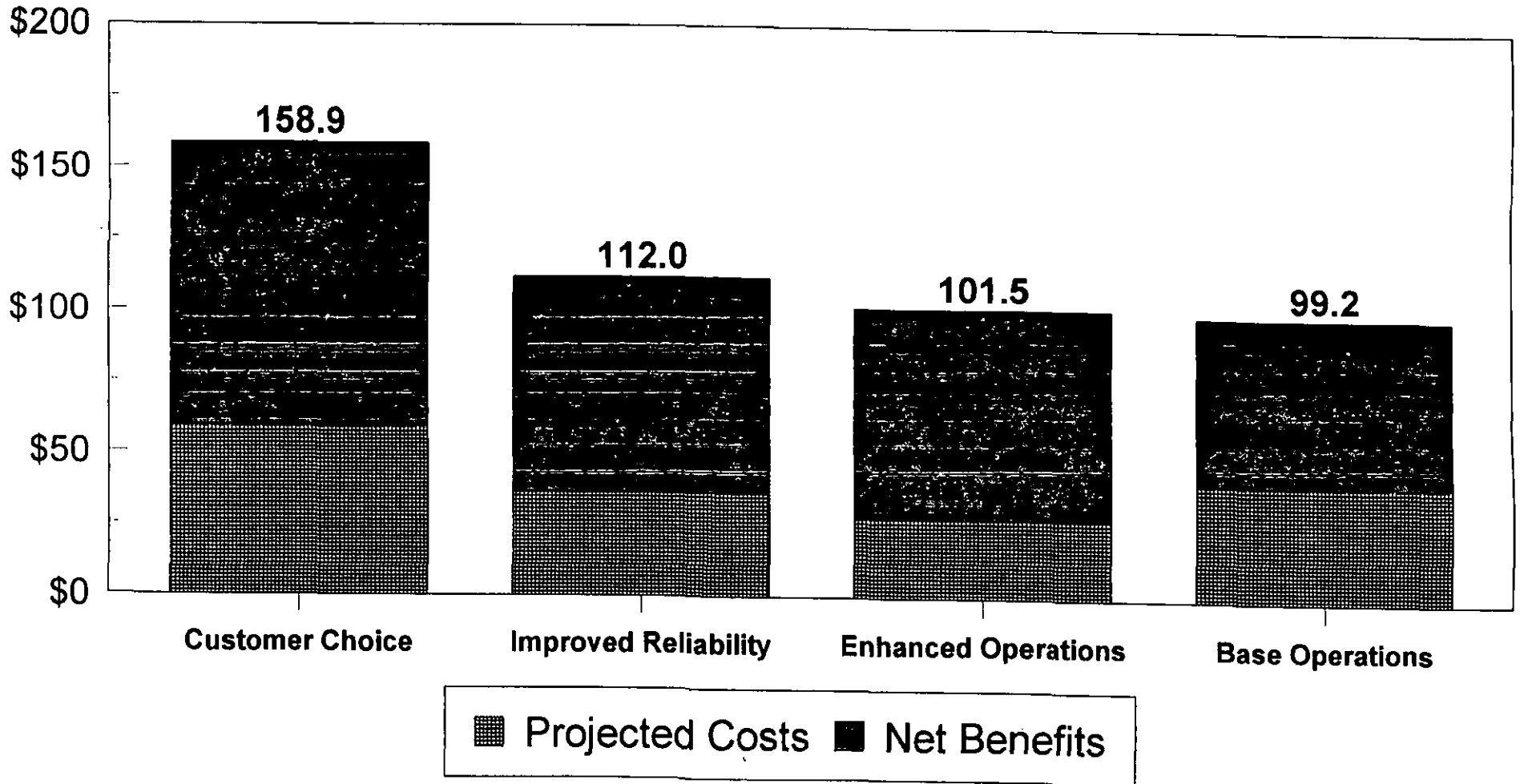


**Net Benefits**



# Customer Advanced Reliability System Overview - Total Benefits

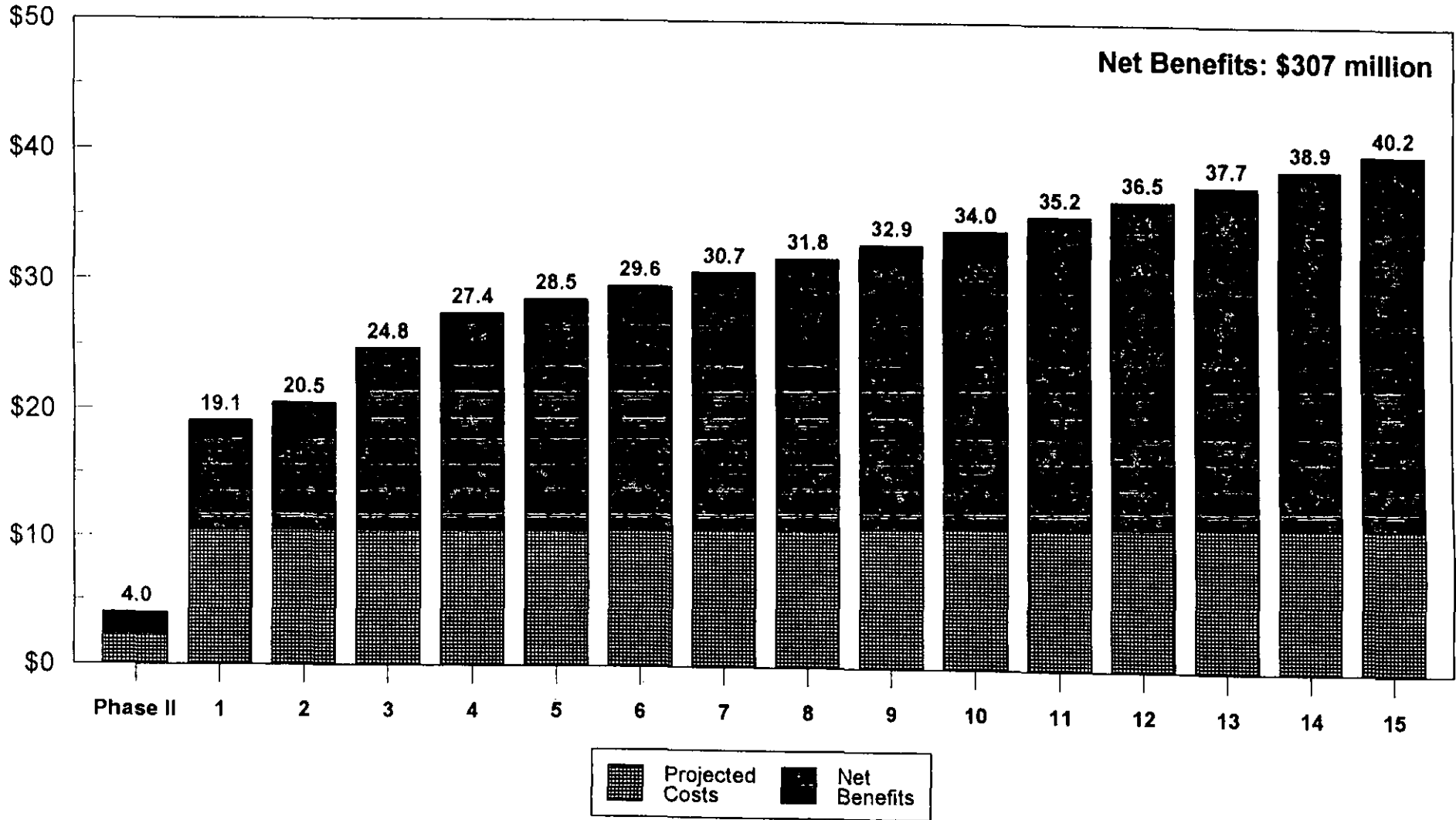
Millions



Projected Costs: Approximately \$164.7 million for Itron Services Agreement

# Customer Advanced Reliability System Overview - Annual Benefits

Millions



Projected Costs: Approximately \$164.7 million for Itron Services Agreement

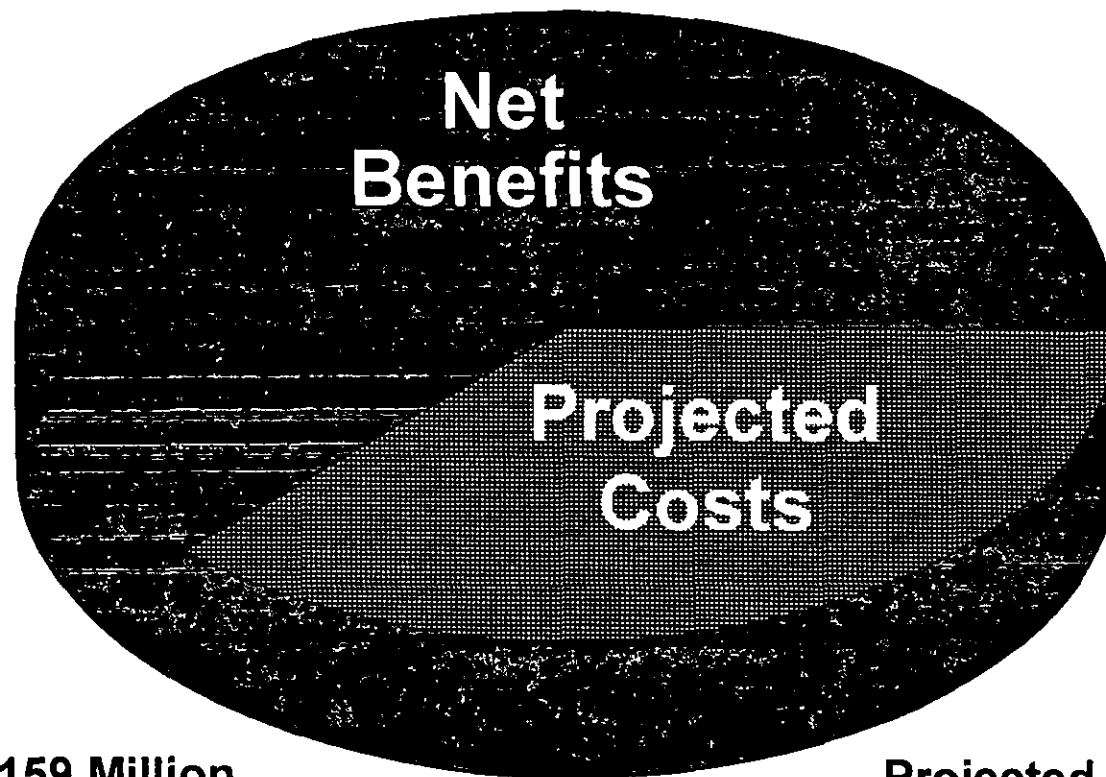
# Customer Advanced Reliability System Overview - Summary

Year	Customer Choice	Improved Reliability	Enhanced Operations	Base Operations	Total Benefits	<i>Itron Contract</i> Projected Costs	Net Benefits
Phase II	779,789	151,249	1,255,668	1,826,635	\$4,013,342	\$2,388,150	\$1,625,192
1	4,707,347	5,670,239	3,628,195	5,059,709	\$19,065,490	\$10,499,508	\$8,565,982
2	5,537,216	5,949,360	3,746,080	5,227,343	\$20,459,999	\$10,499,508	\$9,960,491
3	6,367,683	7,041,764	5,930,990	5,426,201	\$24,766,638	\$10,499,508	\$14,267,130
4	7,199,063	7,601,351	7,033,113	5,596,902	\$27,430,429	\$10,501,734	\$16,928,695
5	8,031,385	7,628,391	7,052,467	5,805,331	\$28,517,574	\$10,527,848	\$17,989,727
6	8,864,677	7,656,243	7,072,402	5,992,085	\$29,585,407	\$10,583,728	\$19,001,679
7	9,698,968	7,684,930	7,092,934	6,210,513	\$30,687,345	\$10,668,733	\$20,018,612
8	10,534,287	7,714,478	7,114,083	6,421,963	\$31,784,811	\$10,759,584	\$21,025,227
9	11,370,666	7,744,912	7,135,866	6,650,392	\$32,901,836	\$10,850,450	\$22,051,386
10	12,208,136	7,776,260	7,178,302	6,882,774	\$34,045,471	\$10,941,331	\$23,104,140
11	13,046,730	7,808,548	7,267,412	7,113,102	\$35,235,791	\$11,032,225	\$24,203,566
12	13,886,482	7,841,804	7,360,215	7,371,404	\$36,459,905	\$11,123,133	\$25,336,772
13	14,727,427	7,876,058	7,456,731	7,607,529	\$37,667,746	\$11,211,972	\$26,455,773
14	15,569,600	7,911,340	7,556,984	7,893,894	\$38,931,818	\$11,278,747	\$27,653,070
15	16,413,038	7,947,680	7,660,994	8,147,924	\$40,169,636	\$11,339,571	\$28,830,065
<b>Total</b>	<b>\$158,942,494</b>	<b>\$112,004,608</b>	<b>\$101,542,434</b>	<b>\$99,233,701</b>	<b>\$471,723,236</b>	<b>\$164,705,731</b>	<b>\$307,017,505</b>

**CUSTOMER CHOICE**

# Customer Advanced Reliability System

## Customer Choice - Total Benefits



**Total Benefits: \$159 Million**

- Real-Time Pricing
- Time of Use Pricing
- Load Profiling
- Group Consolidated Consumption Metering

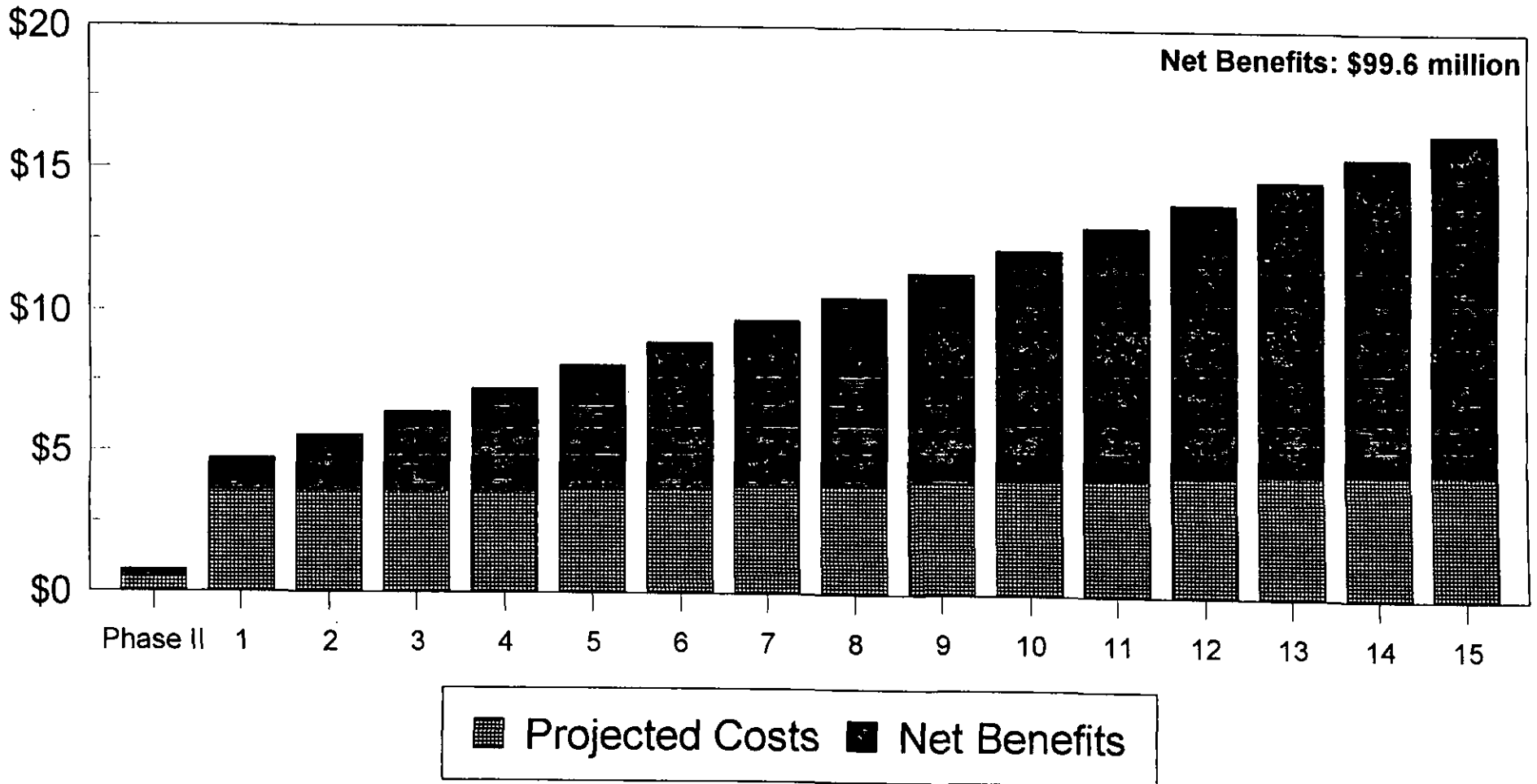
**Projected Costs: \$59.3 Million**

- Itron Services Agreement

# Customer Advanced Reliability System

## Customer Choice - Annual Benefits

Millions



**Projected Costs: Approximately \$300,000 per month plus optional per meter per month charges for advanced services.**

## Customer Advanced Reliability System Customer Choice - Summary

Year	Competitive Services	Meter Purchases	Total Benefits	Itron Contract	
				Projected Costs	Net Benefits
Phase II	0	779,789	\$779,789	\$494,100	\$285,689
1	3,721,660	985,687	\$4,707,347	\$3,600,000	\$1,107,347
2	4,521,660	1,015,556	\$5,537,216	\$3,600,000	\$1,937,216
3	5,321,660	1,046,023	\$6,367,683	\$3,600,000	\$2,767,683
4	6,121,660	1,077,403	\$7,199,063	\$3,602,226	\$3,596,837
5	6,921,660	1,109,725	\$8,031,385	\$3,628,340	\$4,403,046
6	7,721,660	1,143,017	\$8,864,677	\$3,684,220	\$5,180,457
7	8,521,660	1,177,308	\$9,698,968	\$3,769,225	\$5,929,743
8	9,321,660	1,212,627	\$10,534,287	\$3,860,076	\$6,674,211
9	10,121,660	1,249,006	\$11,370,666	\$3,950,942	\$7,419,723
10	10,921,660	1,286,476	\$12,208,136	\$4,041,823	\$8,166,313
11	11,721,660	1,325,070	\$13,046,730	\$4,132,717	\$8,914,013
12	12,521,660	1,364,822	\$13,886,482	\$4,223,625	\$9,662,857
13	13,321,660	1,405,767	\$14,727,427	\$4,312,464	\$10,414,963
14	14,121,660	1,447,940	\$15,569,600	\$4,379,239	\$11,190,361
15	14,921,660	1,491,378	\$16,413,038	\$4,440,063	\$11,972,975
<b>Total</b>	<b>\$139,824,900</b>	<b>\$19,117,594</b>	<b>\$158,942,494</b>	<b>\$59,319,061</b>	<b>\$99,623,433</b>

Competitive Services includes, but is not limited to, Real-time Pricing, Time of Use Pricing, Load Profiling and Group Consolidated Consumption Metering.

These capabilities are absolutely essential to enable Duquesne Light to comply with future competitive obligations related to Customer Choice.

# Competitive Services

## **Customer Advanced Reliability System Customer Choice - Competitive Services**

Estimated Revenues: An average of approximately 800,000 per month

Source: Industry & DLCo Marketing Group Estimates

*The following statements are excerpts from DLCo and ITRON News Releases:*

Over time, DLCo will develop the capabilities of the Customer Advanced Reliability System and provide customers with new products and services that enable the company to compete in a de-regulated electric industry. With more information about individual customer use, flexible rates could be tailored to provide added value to customers.

The Customer Advanced Reliability System's ability to process information about power delivery will provide customers new choices and greater convenience. For example, customers would be able to determine which day of the month to pay their bills.

The Customer Advanced Reliability System will enable development of a daily profile of the electricity usage of each customer.

The Fixed Network will provide DLCo with a wide variety of advanced meter reading capabilities:

- Daily scheduled consumption meter readings
- Real-time on-demand readings
- Start-and-end of service readings
- Time-of-use readings

Customers will be able to request eclectic service to start or stop on any hour of any day.

Customers who have electric meters inside their homes will no longer have to provide access to have their meters read.

# Meter Purchases

## Customer Advanced Reliability System Customer Choice - Meter Purchases

Year	Single Phase	Three Phase	Overhead	Benefits	
				Estimated Costs	Eliminated Costs
Phase II	585,626	278,353	170,204	\$1,034,183	\$779,789
1	558,164	265,300	162,222	\$985,687	\$985,687
2	575,078	273,340	167,138	\$1,015,556	\$1,015,556
3	592,330	281,540	172,152	\$1,046,023	\$1,046,023
4	610,100	289,986	177,317	\$1,077,403	\$1,077,403
5	628,403	298,686	182,637	\$1,109,725	\$1,109,725
6	647,255	307,646	188,116	\$1,143,017	\$1,143,017
7	666,673	316,876	193,759	\$1,177,308	\$1,177,308
8	686,673	326,382	199,572	\$1,212,627	\$1,212,627
9	707,273	336,173	205,559	\$1,249,006	\$1,249,006
10	728,492	346,258	211,726	\$1,286,476	\$1,286,476
11	750,346	356,646	218,078	\$1,325,070	\$1,325,070
12	772,857	367,346	224,620	\$1,364,822	\$1,364,822
13	796,043	378,366	231,358	\$1,405,767	\$1,405,767
14	819,924	389,717	238,299	\$1,447,940	\$1,447,940
15	844,521	401,408	245,448	\$1,491,378	\$1,491,378
<b>Total</b>	<b>\$10,969,760</b>	<b>\$5,214,022</b>	<b>\$3,188,205</b>	<b>\$19,371,987</b>	<b>\$19,117,594</b>

### Assumptions / Definitions:

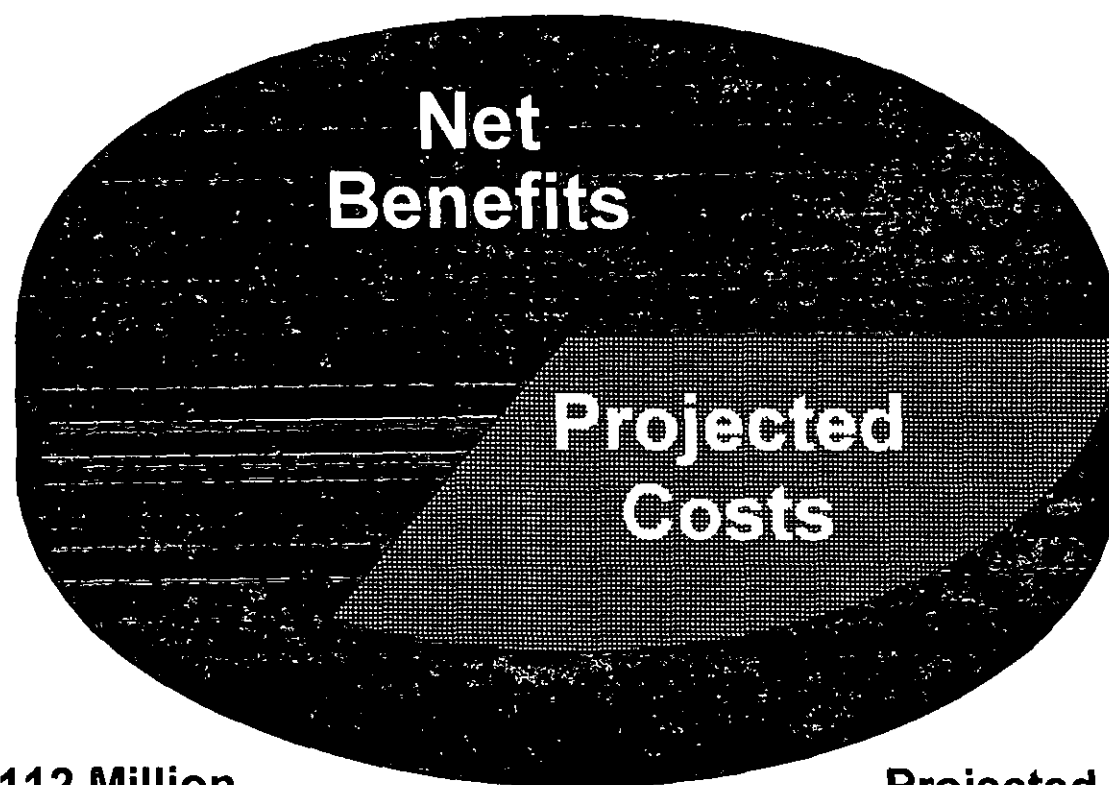
- > Estimated costs will not be fully eliminated until the commencement of Phase III.
- > "Meter Purchases" relates to activities that will be replaced by the Itron Service Agreement.
- > Replaced activities include, but are not limited to, purchase of single-phase and three-phase meters for growth and replacements.
- > Costs escalate annually based on inflation estimates.
 

Inflation Rate:	3.00%
P&W Rate:	11.00%
A&G Rate:	8.70%
- > "Overheads" include P&W and A&G costs.

**IMPROVED RELIABILITY**

# Customer Advanced Reliability System

## Improved Reliability - Total Benefits



**Total Benefits: \$112 Million**

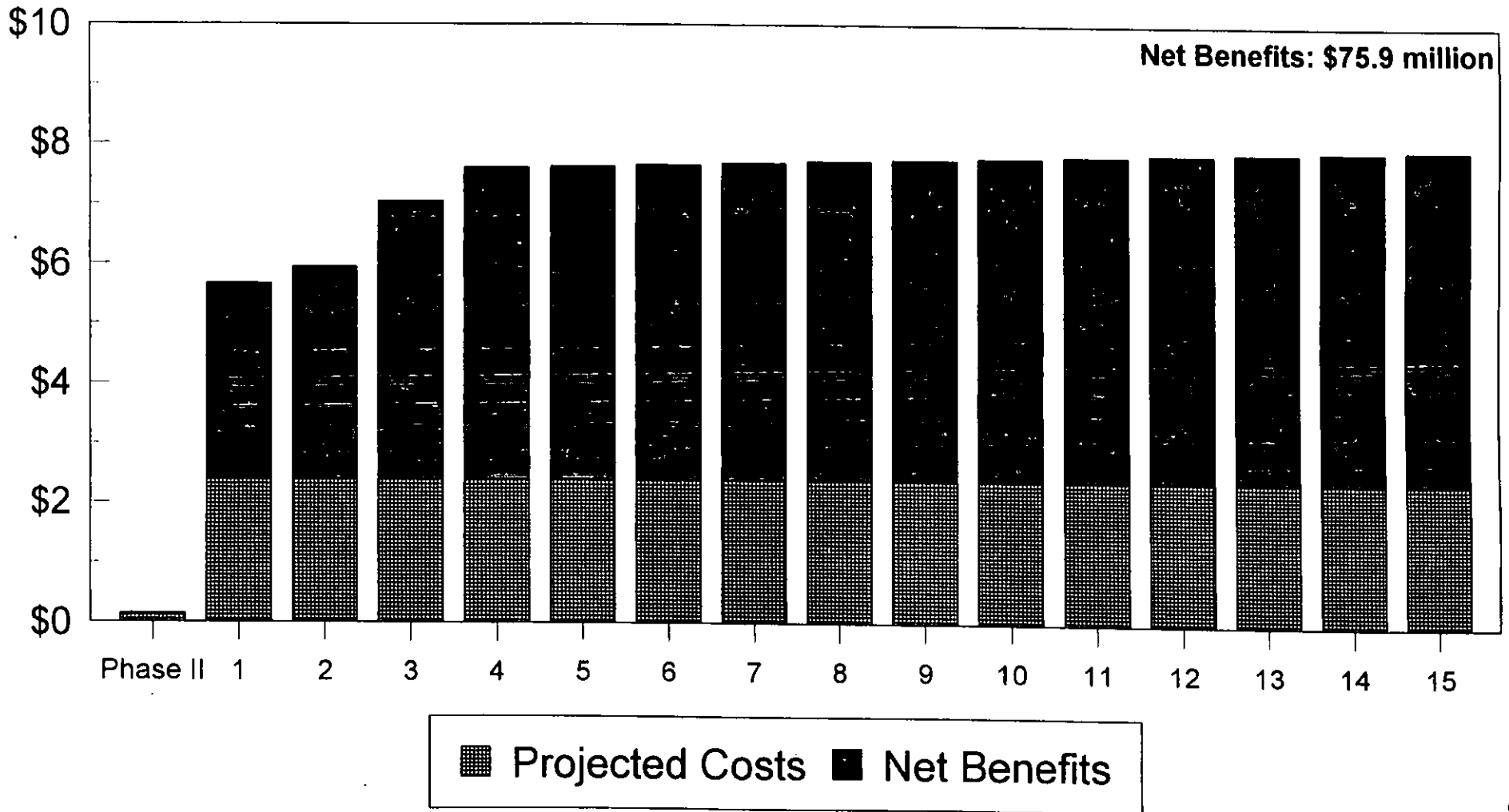
- Real-Time Outage Detection
- Outage Analysis
- Restoration Reporting
- Meter Services

**Projected Costs: \$36 Million**

- Itron Services Agreement

# Customer Advanced Reliability System Improved Reliability - Annual Benefits

Millions



Projected Costs: Approximately \$200,000 per month

## Customer Advanced Reliability System Improved Reliability - Overview

Year	Outage Analysis	Meter Services	Operational Efficiencies	Total Benefits	<i>Itron Contract</i> Projected Costs	Net Benefits
Phase II:	0	151,249	0	\$151,249	\$109,800	\$41,449
1	4,800,000	620,239	250,000	\$5,670,239	\$2,400,000	\$3,270,239
2	4,800,000	849,360	300,000	\$5,949,360	\$2,400,000	\$3,549,360
3	4,800,000	875,098	1,366,667	\$7,041,764	\$2,400,000	\$4,641,764
4	4,800,000	901,351	1,900,000	\$7,601,351	\$2,400,000	\$5,201,351
5	4,800,000	928,391	1,900,000	\$7,628,391	\$2,400,000	\$5,228,391
6	4,800,000	956,243	1,900,000	\$7,656,243	\$2,400,000	\$5,256,243
7	4,800,000	984,930	1,900,000	\$7,684,930	\$2,400,000	\$5,284,930
8	4,800,000	1,014,478	1,900,000	\$7,714,478	\$2,400,000	\$5,314,478
9	4,800,000	1,044,912	1,900,000	\$7,744,912	\$2,400,000	\$5,344,912
10	4,800,000	1,076,260	1,900,000	\$7,776,260	\$2,400,000	\$5,376,260
11	4,800,000	1,108,548	1,900,000	\$7,808,548	\$2,400,000	\$5,408,548
12	4,800,000	1,141,804	1,900,000	\$7,841,804	\$2,400,000	\$5,441,804
13	4,800,000	1,176,058	1,900,000	\$7,876,058	\$2,400,000	\$5,476,058
14	4,800,000	1,211,340	1,900,000	\$7,911,340	\$2,400,000	\$5,511,340
15	4,800,000	1,247,680	1,900,000	\$7,947,680	\$2,400,000	\$5,547,680
<b>Total</b>	<b>\$72,000,000</b>	<b>\$15,287,941</b>	<b>\$24,716,667</b>	<b>\$112,004,608</b>	<b>\$36,109,800</b>	<b>\$75,894,808</b>

Outage Analysis includes, but is not limited to, Real-time Outage Detection and Restoration Reporting.

Superior reliability is the single most important component to ensure that customers choose Duquesne Light as their electric service provider in a competitive environment.

# Outage Analysis

## **Customer Advanced Reliability System Improved Reliability - Outage Analysis**

Estimated Revenues: An average of approximately \$400,000 per month  
Source: Industry & DLCo Marketing Group Estimates

*The following statements are excerpts from DLCo and ITRON News Releases:*

The Customer Advanced Reliability System will raise the standard for customer service to a new threshold because service personnel will be able to respond to customer needs on the basis of immediate real-time information about the status of power delivery at individual homes and businesses.

With the fixed network, customers' use of electricity can be immediately recorded and communicated electronically to a control center in the company. As a result, customer service personnel will have a real-time picture of the status of power delivery across the system and for individual customers.

Customers will benefit from increased energy security. The system will inform the company when a customer is out of service. Customers will not have to report the outage, and restoration can begin more quickly. When power is restored to the home, the system will automatically signal DLCo operators as to exactly where problems have been solved.

The Customer Advanced Reliability System will enable the company to track more effectively electric power load growth. With more real time information about customer demand, the company can improve its ability to respond to the need for higher capacity distribution equipment.

# Meter Services

## Customer Advanced Reliability System Improved Reliability - Meter Services

Year	Labor	Fringes	Transport.	Benefits	
				Estimated Costs	Eliminated Costs
Phase II	626,475	140,957	96,982	\$864,414	\$151,249
1	597,097	134,347	92,435	\$823,879	\$620,239
2	615,564	138,502	95,293	\$849,360	\$849,360
3	634,218	142,699	98,181	\$875,098	\$875,098
4	653,244	146,980	101,127	\$901,351	\$901,351
5	672,841	151,389	104,160	\$928,391	\$928,391
6	693,027	155,931	107,285	\$956,243	\$956,243
7	713,818	160,609	110,504	\$984,930	\$984,930
8	735,232	165,427	113,819	\$1,014,478	\$1,014,478
9	757,289	170,390	117,233	\$1,044,912	\$1,044,912
10	780,008	175,502	120,750	\$1,076,260	\$1,076,260
11	803,408	180,767	124,373	\$1,108,548	\$1,108,548
12	827,510	186,190	128,104	\$1,141,804	\$1,141,804
13	852,335	191,775	131,947	\$1,176,058	\$1,176,058
14	877,906	197,529	135,906	\$1,211,340	\$1,211,340
15	904,243	203,455	139,983	\$1,247,680	\$1,247,680
<b>Total</b>	<b>\$11,744,214</b>	<b>\$2,642,448</b>	<b>\$1,818,083</b>	<b>\$16,204,745</b>	<b>\$15,287,941</b>

### Assumptions / Definitions:

- > Estimated costs will not be fully eliminated until after the fourth month of Phase III.
- > "Meter Services" relates to activities that will be replaced by the Itron Service Agreement.
- > Replaced activities include, but are not limited to, meter shop operations, field meter installations and meter maintenance for single-phase meters. Related activities for three-phase meters are not included.
- > Costs escalate annually based on inflation estimates.      Inflation Rate:      3.00%
- > "Fringes" are calculated as a percentage of labor costs:      Fringes Rate:      22.50%

# Operational Efficiencies

## Customer Advanced Reliability System Improved Reliability - Operational Efficiencies

Year	Customer Services	Power Delivery	Security & Collections	Estimated Costs	Benefits
					Eliminated Costs
Phase II	162,500	1,625,000	108,333	\$1,895,833	\$0
1	250,000	1,500,000	100,000	\$1,850,000	\$250,000
2	300,000	1,500,000	100,000	\$1,900,000	\$300,000
3	300,000	1,500,000	100,000	\$1,900,000	\$1,366,667
4	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
5	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
6	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
7	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
8	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
9	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
10	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
11	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
12	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
13	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
14	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
15	300,000	1,500,000	100,000	\$1,900,000	\$1,900,000
Total	\$4,612,500	\$24,125,000	\$1,608,333	\$30,345,833	\$24,716,667

### Assumptions / Definitions:

- > Estimated costs will not be fully eliminated until after the third year of Phase III.

## Customer Advanced Reliability System Operational Efficiencies - Customer Services, Power Delivery, Security & Collections

### Customer Services

**Projected Costs Eliminated: \$150,000 per year starting in 1996**  
**\$150,000 additional per year starting in 1998**

Source: Service Board Queue Statistics

- **Costs eliminated starting in 1996**

The increased accuracy and customer confidence in meter reading due to the new Customer Advanced Reliability System will result in decreased customer service calls initiated by meter reading questions or billing errors. There is also the benefit of reduced corrected billing. Presently, over 20,000 annual corrected bills are individually handled. Reduction of this process may also decrease accounting overhead.

- **Additional costs eliminated starting in 1998**

The Customer Advanced Reliability System will provide individual customer outage monitoring, which will eliminate over 15% of Duquesne's customer call volume.

### Power Delivery System Management

**Projected Costs Eliminated: \$1,500,000 per year beginning in 2000**

Source: Distribution Transformer Failure Statistics

Over \$1.5 million in annual capital expenditures for distribution transformer replacements can be averted through applications of the new system's information.

**Distribution Transformer Failures**

Year	# of failures	Summer overload	All season overload (20%)	Total overloads	Annual replacement expense
1993	1795	800	358	1158	\$1.56M
1994	1869	800	372	1172	\$1.58M

An average replacement cost of \$1,350 per transformer was used in estimating savings. These estimates assume that distribution transformer load profiles will be derived from the system's data and resources will be available to analyze data and proactively manage customer loading. A majority of the overload failures should be averted.

### Security & Collections

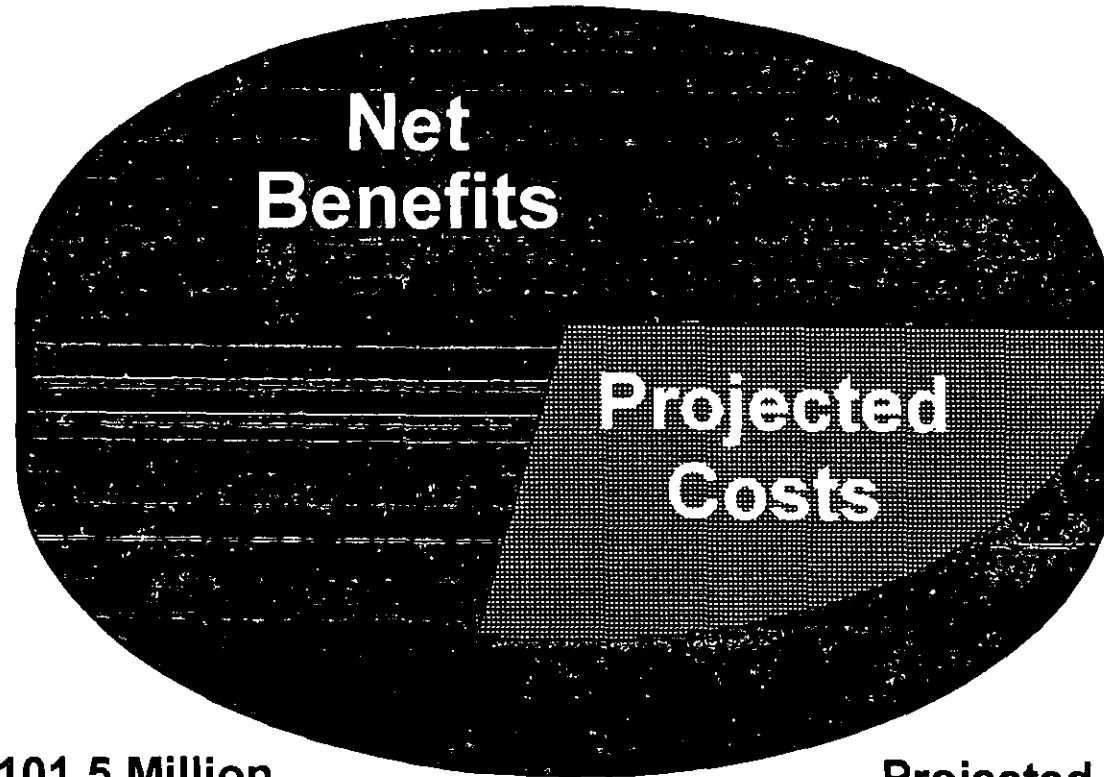
**Projected Costs Eliminated: \$100,000 per year beginning in 2000**

Source: Termination Statistics

The system will provide Credit and Collection with better information for dealing with customers which require personnel to repeatedly connect and disconnect service. These customer sites may have switches installed that are remotely controlled eliminating this labor intensive process and, consequently, labor costs.

**ENHANCED OPERATIONS**

# Customer Advanced Reliability System Enhanced Operations - Total Benefits



**Total Benefits: \$101.5 Million**

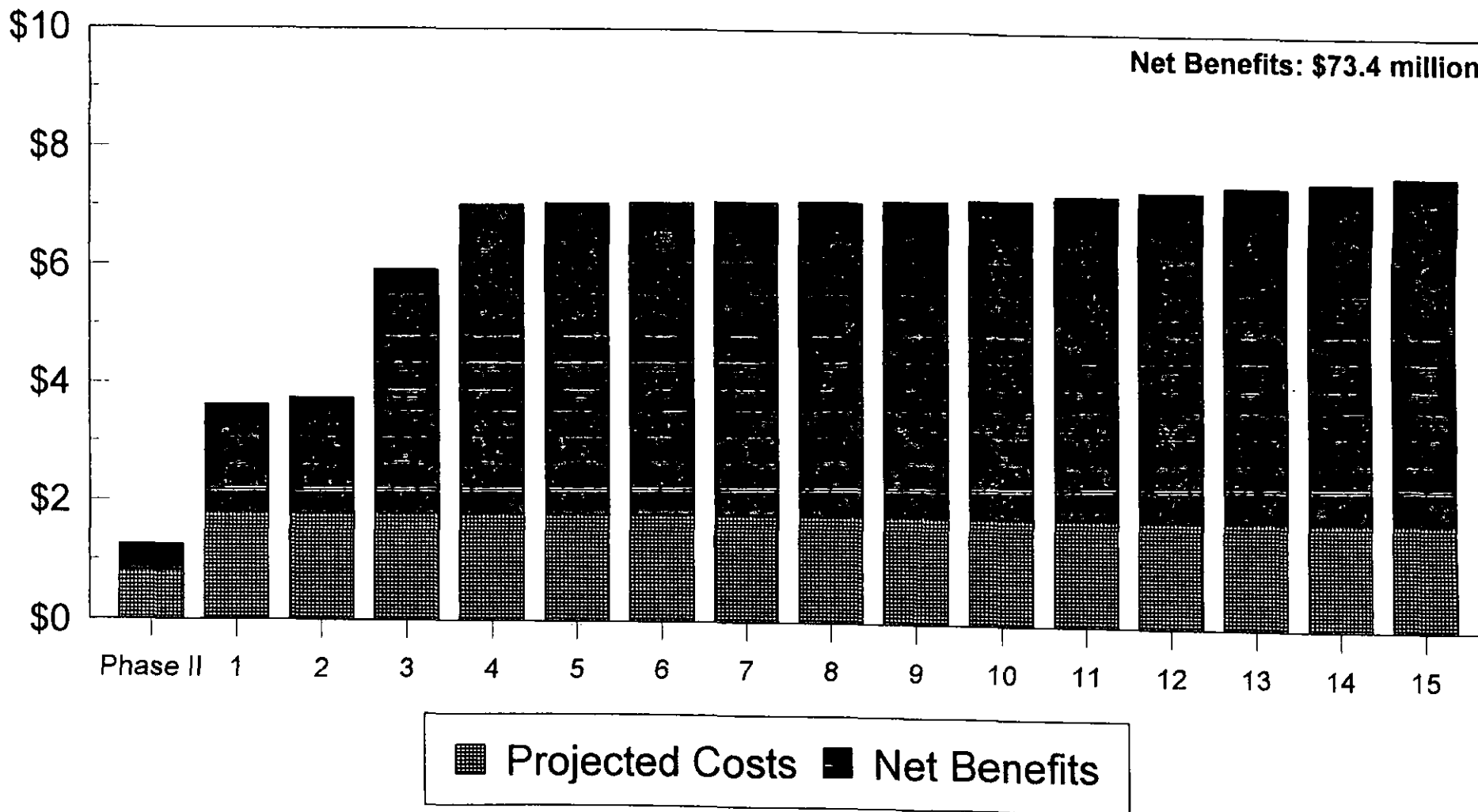
- Virtual Turn-ons and Turn-offs
- Real-time Consumption Reading
- On Request Reads
- Tamper Monitoring and Reporting

**Projected Costs: \$28.1 Million**

- Itron Services Agreement

# Customer Advanced Reliability System Enhanced Operations - Annual Benefits

Millions



Projected Costs: Approximately \$150,000 per month

## Customer Advanced Reliability System Enhanced Operations - Overview

Year	Field Services	Recovered Revenues	Marketing Opportunities	Total Benefits	Projected Costs	Net Benefits
Phase II	197,184	1,058,484	0	\$1,255,668	\$823,500	\$432,168
1	598,528	3,029,667	0	\$3,628,195	\$1,819,908	\$1,808,287
2	616,413	3,129,667	0	\$3,746,080	\$1,819,908	\$1,926,172
3	634,656	3,129,667	2,166,667	\$5,930,990	\$1,819,908	\$4,111,082
4	653,446	3,129,667	3,250,000	\$7,033,113	\$1,819,908	\$5,213,205
5	672,800	3,129,667	3,250,000	\$7,052,467	\$1,819,908	\$5,232,559
6	692,735	3,129,667	3,250,000	\$7,072,402	\$1,819,908	\$5,252,494
7	713,267	3,129,667	3,250,000	\$7,092,934	\$1,819,908	\$5,273,026
8	734,416	3,129,667	3,250,000	\$7,114,083	\$1,819,908	\$5,294,175
9	756,199	3,129,667	3,250,000	\$7,135,866	\$1,819,908	\$5,315,958
10	778,635	3,129,667	3,270,000	\$7,178,302	\$1,819,908	\$5,358,394
11	801,745	3,129,667	3,336,000	\$7,267,412	\$1,819,908	\$5,447,504
12	825,548	3,129,667	3,405,000	\$7,360,215	\$1,819,908	\$5,540,307
13	850,064	3,129,667	3,477,000	\$7,456,731	\$1,819,908	\$5,636,823
14	875,317	3,129,667	3,552,000	\$7,556,984	\$1,819,908	\$5,737,076
15	901,327	3,129,667	3,630,000	\$7,660,994	\$1,819,908	\$5,841,086
<b>Total</b>	<b>\$11,302,278</b>	<b>\$47,903,489</b>	<b>\$42,336,667</b>	<b>\$101,542,434</b>	<b>\$28,122,120</b>	<b>\$73,420,314</b>

*Itron Contract*

Field Services includes, but is not limited to, Virtual Turn-ons & Turn-offs and On Request Reads.

Revenue Recovery includes, but is not limited to, Improved Reading Accuracy and reduction in Theft of Service.

Marketing Opportunity includes, but is not limited to, Cycle Choice and Customized Billing.

# Field Services

**Customer Advanced Reliability System  
Enhanced Operations - Field Services**

Year	Labor	Fringes	Transport.	Materials	Contract	Overtime	OT Fringes	Misc.	Estimated Costs	Benefits Eliminated Costs
Phase II	437,551	98,449	66,700	5,194	2,285	8,559	514	9,009	\$628,259	\$197,184
1	417,033	93,832	63,572	4,950	2,178	8,158	489	8,316	\$598,528	\$598,528
2	429,670	96,676	65,498	5,100	2,244	8,405	504	8,316	\$616,413	\$616,413
3	442,560	99,576	67,463	5,253	2,311	8,657	519	8,316	\$634,656	\$634,656
4	455,837	102,563	69,487	5,411	2,381	8,917	535	8,316	\$653,448	\$653,446
5	469,512	105,640	71,572	5,573	2,452	9,184	551	8,316	\$672,800	\$672,800
6	483,597	108,809	73,719	5,740	2,526	9,460	568	8,316	\$692,735	\$692,735
7	498,105	112,074	75,930	5,912	2,601	9,743	585	8,316	\$713,267	\$713,267
8	513,048	115,436	78,208	6,090	2,679	10,036	602	8,316	\$734,416	\$734,416
9	528,440	118,899	80,555	6,272	2,760	10,337	620	8,316	\$756,199	\$756,199
10	544,293	122,466	82,971	6,461	2,843	10,647	639	8,316	\$778,635	\$778,635
11	560,622	126,140	85,460	6,654	2,928	10,966	658	8,316	\$801,745	\$801,745
12	577,440	129,924	88,024	6,854	3,016	11,295	678	8,316	\$825,548	\$825,548
13	594,764	133,822	90,665	7,060	3,106	11,634	698	8,316	\$850,064	\$850,064
14	612,607	137,836	93,385	7,271	3,199	11,983	719	8,316	\$875,317	\$875,317
15	630,985	141,972	96,186	7,490	3,295	12,343	741	8,316	\$901,327	\$901,327
<b>Total</b>	<b>\$8,196,062</b>	<b>\$1,844,114</b>	<b>\$1,249,396</b>	<b>\$97,284</b>	<b>\$42,805</b>	<b>\$160,324</b>	<b>\$9,619</b>	<b>\$133,749</b>	<b>\$11,733,364</b>	<b>\$11,302,278</b>

**Assumptions / Definitions:**

- > Projected costs will not be fully eliminated until the commencement of Phase III.
- > "Current Field Service Processes" relates to activities that will be replaced by the Itron Service Agreement.
- > Replaced activities include, but are not limited to, dual, re-read, and special re-read service orders.
- > Costs escalate annually based on inflation estimates.                      Inflation Rate:    3.00%
- > "Fringes" are calculated as a percentage of labor costs.                      Fringes Rate:    22.50%
- > "OT Fringes" are calculated as a percentage of overtime costs.                      Fringes Rate:    6.00%
- > "Contract" expenses are leased items.

# Recovered Revenues

## Customer Advanced Reliability System Enhanced Operations - Recovered Revenues

Year	Inaccurate Meters	Reduction of Theft	Shorter Outages	Defective D3S Meters	Vendor Services	Benefits
						Recovered Revenues
Phase II	425,978	511,173	0	121,333	0	\$1,058,484
1	1,000,000	1,200,000	200,000	284,835	344,832	\$3,029,667
2	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
3	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
4	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
5	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
6	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
7	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
8	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
9	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
10	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
11	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
12	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
13	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
14	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
15	1,000,000	1,200,000	300,000	284,835	344,832	\$3,129,667
<b>Total</b>	<b>\$15,425,978</b>	<b>\$18,511,173</b>	<b>\$4,400,000</b>	<b>\$4,393,858</b>	<b>\$5,172,480</b>	<b>\$47,903,489</b>

### Assumptions / Definitions:

- > Lost revenues will not fully be recovered until the commencement of Phase III.
- > "Recovered Revenues" relates to monies that would be lost or not realized if DLCo did not enter into the Itron Service Agreement.
- > The annual estimates assume no change in electric rates over the life of the agreement.

## **Customer Advanced Reliability System**

### **Recovered Revenues - Inaccurate Meters, Reduction of Theft & Shorter Outages**

#### **Replacement of Inaccurate Meters**

**Projected Costs Eliminated: \$1,000,000 per year beginning in 2000**

**Source: Extrapolation of Meter Test Results**

During full scale implementation, all meters will be either replaced or refurbished. The elimination of all defective meters will be a byproduct of this process. Analysis of meters currently in the field indicates that DLCo will realize a net revenue gain of about \$1.3 million annually from removing inaccurate meters. Approximately \$300,000 of these annual savings will come from the replacement of D3S meters which was accounted for separately.

#### **Reduction of Theft of Service**

**Projected Costs Eliminated: \$1,200,000 per year beginning in 2000**

**Source: Edison Electric Institute**

EEI estimates that utilities lose close to 1% of annual revenues due to energy theft. At this rate, it is estimated that DLCo possibly loses over \$10 million a year to theft of service.

The system provides the following capabilities to scan for potential energy theft:

- ⇒ Daily monitoring of inactive accounts for unauthorized use
- ⇒ Identification of unusual energy use patterns
- ⇒ Immediate notice of tamper detection

The system's theft awareness capabilities along with deterrence due to publicity will reduce theft of service by 10% or about \$1.2 million annually for DLCo. Theft could further be reduced by as much as 30%, if additional security resources were available to determine theft and subsequently regulations were changed to expedite termination when theft is identified.

#### **Shorter Outages**

**Projected Costs Eliminated: \$300,000 per year beginning in 2000**

**Source: Review of Annual System Disturbances**

System disturbances result in approximately 6 million kWh of lost revenue per year. At an average of \$.10 cents per kWh, DLCo loses approximately \$600,000 annually due to unplanned outages. The system's outage analysis capabilities will provide individual customer power outage notification. It is estimated that quicker restorations due to individual outage information along with fewer outages due to a reduction in transformer failures, will reduce annual lost revenue by 50% or \$300,000.

## Customer Advanced Reliability System Recovered Revenues - Defective D3S Meters

Year	Lost \$ Per Month	Estimated Revenues	Benefits Recovered Revenues
Phase II	23,736	\$308,571	\$121,333
1	23,736	\$284,835	\$284,835
2	23,736	\$284,835	\$284,835
3	23,736	\$284,835	\$284,835
4	23,736	\$284,835	\$284,835
5	23,736	\$284,835	\$284,835
6	23,736	\$284,835	\$284,835
7	23,736	\$284,835	\$284,835
8	23,736	\$284,835	\$284,835
9	23,736	\$284,835	\$284,835
10	23,736	\$284,835	\$284,835
11	23,736	\$284,835	\$284,835
12	23,736	\$284,835	\$284,835
13	23,736	\$284,835	\$284,835
14	23,736	\$284,835	\$284,835
15	23,736	\$284,835	\$284,835
<b>Total</b>	<b>\$379,780</b>	<b>\$4,581,096</b>	<b>\$4,393,858</b>

### Assumptions / Definitions:

- > Lost revenues will not fully be recovered until the commencement of Phase III.
- > "Defective D3S Meters" relates to lost revenues that would not be recovered if DLCo did not enter into the Itron Service agreement.
- > DLCo has about 17,000 D3S meters that have not been replaced.
- > Based on historical statistics, it is estimated that 5% of the remaining D3S meters are defective, which equates to about 850 meters.
- > A random sampling of 100 D3S meters over a two year period indicated that DLCo averaged about \$335 in lost revenue per year on each meter.
- > The annual estimates assume no change in electric rates over the life of the agreement.

## Customer Advanced Reliability System Enhanced Operations - Vendor Services

Year	Pole Rentals	Energy Charges	Benefits	
			Estimated Revenues	Realized Revenues
Phase II	269,568	104,000	\$373,568	\$0
1	248,832	96,000	\$344,832	\$344,832
2	248,832	96,000	\$344,832	\$344,832
3	248,832	96,000	\$344,832	\$344,832
4	248,832	96,000	\$344,832	\$344,832
5	248,832	96,000	\$344,832	\$344,832
6	248,832	96,000	\$344,832	\$344,832
7	248,832	96,000	\$344,832	\$344,832
8	248,832	96,000	\$344,832	\$344,832
9	248,832	96,000	\$344,832	\$344,832
10	248,832	96,000	\$344,832	\$344,832
11	248,832	96,000	\$344,832	\$344,832
12	248,832	96,000	\$344,832	\$344,832
13	248,832	96,000	\$344,832	\$344,832
14	248,832	96,000	\$344,832	\$344,832
15	248,832	96,000	\$344,832	\$344,832
<b>Total</b>	<b>\$4,002,048</b>	<b>\$1,544,000</b>	<b>\$5,546,048</b>	<b>\$5,172,480</b>

### Assumptions / Definitions:

- > Projected revenues will not be realized until the commencement of Phase III.
- > "Services Provided to Vendor" relates to revenues that would not be realized if DLCo did not enter into the Itron Service Agreement.
- > Revenues for "Pole Rentals" are based on DLCo's projected standard monthly rental fee per pole. Pole Rental Fee: \$2.16
- > It is estimated that Itron will make 12,040 pole connections of which 80% are on DLCo poles.
- > Revenues for "Energy Charges" are based on electric usage for fixed network components such as CCU's and NCN's. Monthly Usage: \$8,000
- > The monthly estimates assume no change in electric rates over the life of the agreement.

# Marketing Opportunities

# Customer Advanced Reliability System Enhanced Operations - Marketing Opportunities

Year						Benefits
	Power Outage Notification	Itemized Billing	Defined Cycle Billing	Summary Billing	Vendor Access Fees	Recovered Revenues
Phase II	0	0	0	0	0	\$0
1	0	0	0	0	0	\$0
2	0	0	0	0	0	\$0
3	1,200,000	800,000	100,000	66,667	0	\$2,166,667
4	1,800,000	1,200,000	150,000	100,000	0	\$3,250,000
5	1,800,000	1,200,000	150,000	100,000	0	\$3,250,000
6	1,800,000	1,200,000	150,000	100,000	0	\$3,250,000
7	1,800,000	1,200,000	150,000	100,000	0	\$3,250,000
8	1,800,000	1,200,000	150,000	100,000	0	\$3,250,000
9	1,800,000	1,200,000	150,000	100,000	0	\$3,250,000
10	1,800,000	1,200,000	150,000	100,000	20,000	\$3,270,000
11	1,800,000	1,200,000	150,000	100,000	86,000	\$3,336,000
12	1,800,000	1,200,000	150,000	100,000	155,000	\$3,405,000
13	1,800,000	1,200,000	150,000	100,000	227,000	\$3,477,000
14	1,800,000	1,200,000	150,000	100,000	302,000	\$3,552,000
15	1,800,000	1,200,000	150,000	100,000	380,000	\$3,630,000
<b>Total</b>	<b>\$22,800,000</b>	<b>\$15,200,000</b>	<b>\$1,900,000</b>	<b>\$1,266,667</b>	<b>\$1,170,000</b>	<b>\$42,336,667</b>

## **Customer Advanced Reliability System Marketing Opportunities - Power Outage Notification, Itemized Billing, Defined Cycle Billing & Summary Billing**

### **Power Outage Notification**

**Estimated Revenues: \$1,800,000 per year beginning in 2000**

**Source: Focus Groups conducted by DLCo in 1994**

Power outage notification service will provide detailed and real time information to customers on their power status conditions. The service is based on the system's ability to notify DLCo in the event of a power outage. However, the customer's perceived value of the service is maximized when they receive this information in a timely manner. For example, a DLCo customer, vacationing in Florida during the winter, would be notified by DLCo if his service is disrupted for more than 1 hour. When notified they could contact a relative to check on their house. In essence, this service will put "power security" information at the customer's finger tips at their discretion. Focus groups conducted by DLCo in 1994 indicate a 10% market penetration is achievable at a \$3 per month fee, or \$1.8 million in annual revenues.

### **Itemized Billing**

**Estimated Revenues: \$1,200,000 per year beginning in 2000**

**Source: Unpublished EPRI study conducted in 1994 for PSE&G**

Itemized billing will provide customers with an electric bill broken down per appliance usage. They will see their monthly consumption and energy cost for their air conditioning, hot water heater, dishwasher, refrigerator, or any major appliance they choose. This is the first step in customer education to distinguish the value of electricity by end use. Estimates based on EPRI research indicate a 20% market penetration is achievable at a \$1 per month fee, or \$1.2 million in annual revenues.

### **Defined Cycle Billing**

**Estimated Revenues: \$150,000 per year beginning in 2000**

**Source: Focus Groups conducted by DLCo in 1993**

Defined cycle billing gives customers the ability to choose their meter read date and subsequent billing date. This service will be bundled with EFT or a phone call payment process eliminating the need for customer mailing in a payment. Focus groups conducted by DLCo in 1993 indicate a 5% market penetration is achievable at a \$.50 cents per month fee, or \$150,000 in annual revenues.

### **Summary Billing**

**Estimated Revenues: \$100,000 per year beginning in 2000**

**Source: Marketing Estimates**

Summary billing and load profiling are administrative services for the commercial and industrial segments. Initial estimates are for \$100,000 in annual incremental revenue.

## Customer Advanced Reliability System Marketing Opportunities - Vendor Access Fees

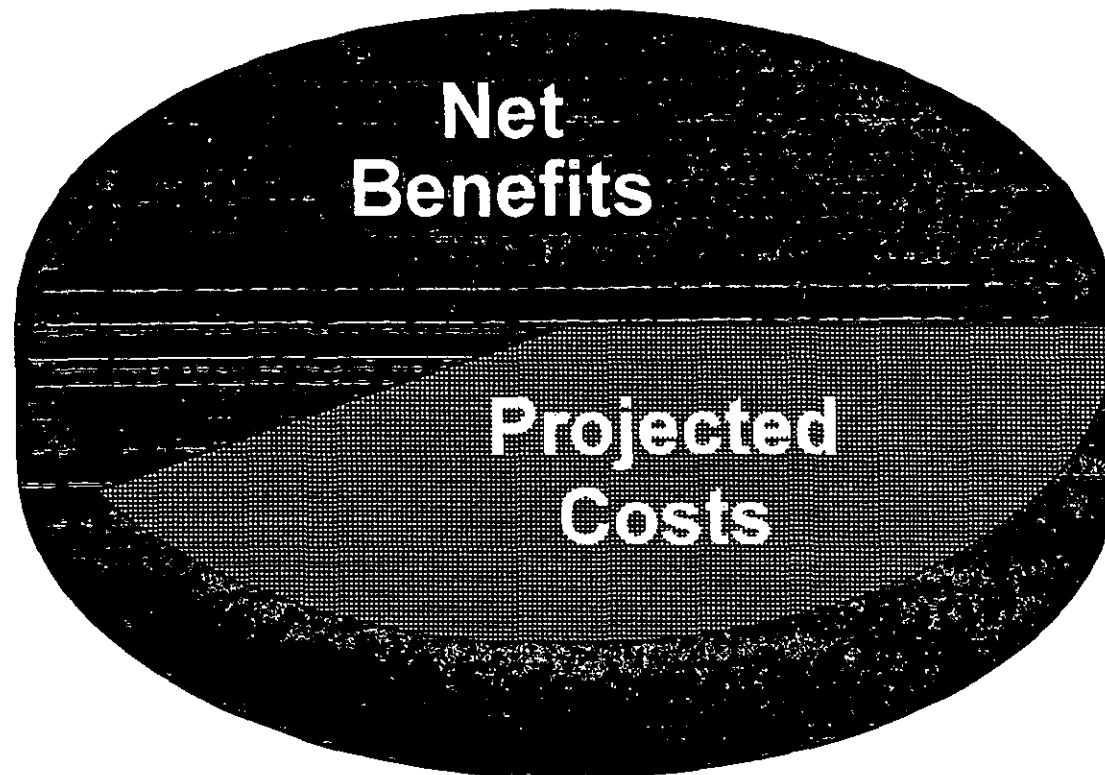
Year	Estimated Revenues	Fee Calcs	Cumulative Fees	Fees Paid
Phase II	0	0	0	\$0
1	100,000	5,000	5,000	\$0
2	500,000	25,000	30,000	\$0
3	1,000,000	50,000	80,000	\$0
4	1,500,000	75,000	155,000	\$0
5	1,600,000	80,000	235,000	\$0
6	1,700,000	51,000	286,000	\$0
7	1,800,000	54,000	340,000	\$0
8	1,900,000	57,000	397,000	\$0
9	2,000,000	60,000	457,000	\$0
10	2,100,000	63,000	520,000	\$20,000
11	2,200,000	66,000		\$86,000
12	2,300,000	69,000		\$155,000
13	2,400,000	72,000		\$227,000
14	2,500,000	75,000		\$302,000
15	2,600,000	78,000		\$380,000
<b>Total</b>	<b>\$26,200,000</b>	<b>\$880,000</b>		<b>\$1,170,000</b>

### Assumptions / Definitions:

- > The equipment installed for the DLCo Fixed Network may provide capacity in excess of the DLCo requirements.
- > Itron may use, lease, license and sell rights to such excess capacity to provide services to third parties provided that they pay DLCo an access fee.
- > For the first 5 years of the agreement, access fees will be equal to 5% of Itron's gross revenues related to the use of excess capacity for third party services.
- > For the remainder of the agreement, access fees will be equal to 3% of Itron's gross revenues related to the use of excess capacity for third party services.
- > The first \$500,000 in access fees that become due will be calculated and tracked, but will not be paid.

**BASE OPERATIONS**

# Customer Advanced Reliability System Base Operations - Total Benefits

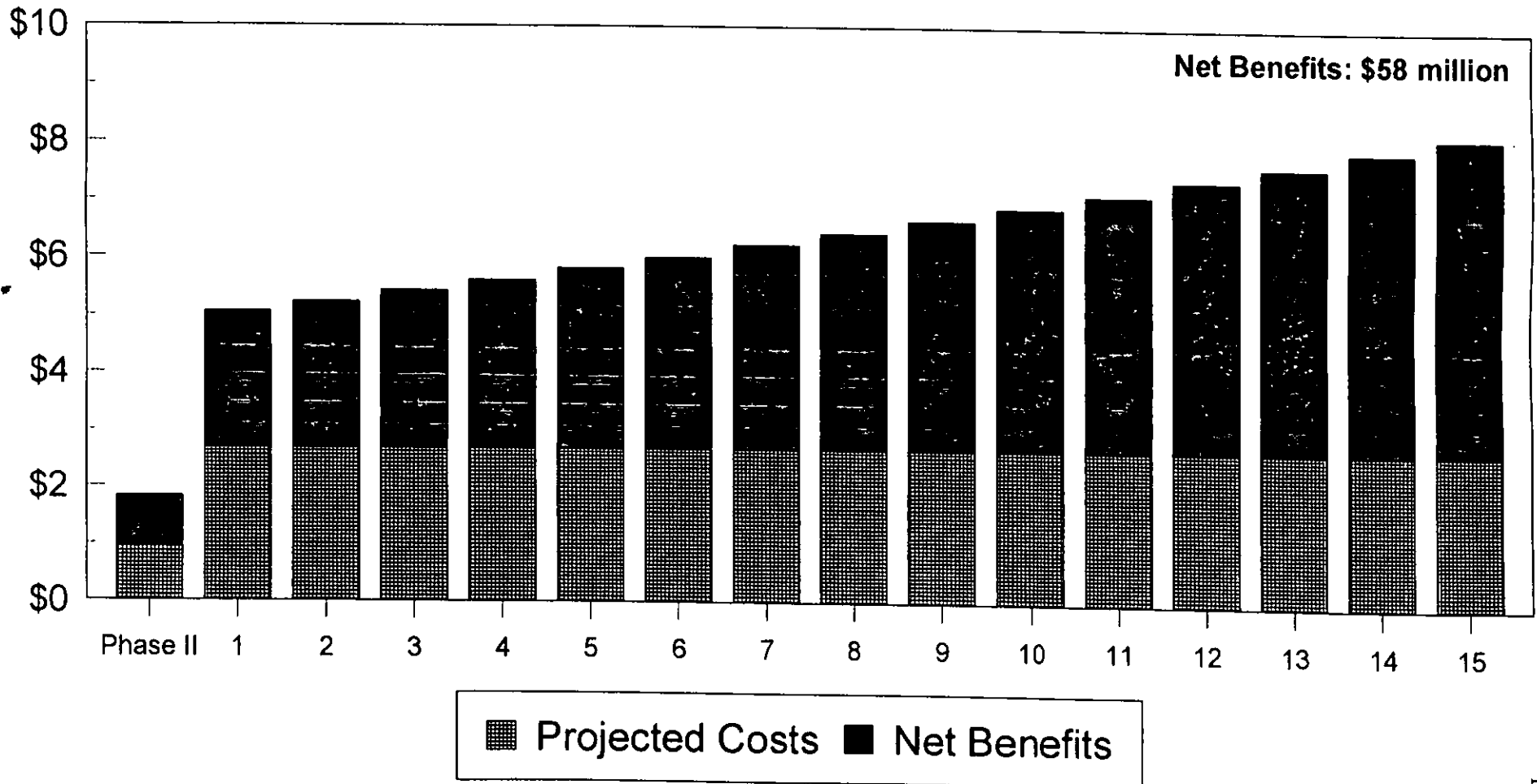


**Total Benefits: \$99.2 Million**  
- Basic Meter Reading Services

**Projected Costs: \$41.2 Million**  
- Itron Services Agreement

# Customer Advanced Reliability System Base Operations - Annual Benefits

Millions



Projected Costs: Approximately \$225,000 per month  
 - 35 cents per meter per month based on an average of 638,000 meters

## Customer Advanced Reliability System Base Operations - Overview

Year	Meter Reading Services	<i>Itron Contract</i> Projected Costs	Net Benefits
Phase II	\$1,826,635	\$960,750	\$865,885
1	\$5,059,709	\$2,679,600	\$2,380,109
2	\$5,227,343	\$2,679,600	\$2,547,743
3	\$5,426,201	\$2,679,600	\$2,746,601
4	\$5,596,902	\$2,679,600	\$2,917,302
5	\$5,805,331	\$2,679,600	\$3,125,731
6	\$5,992,085	\$2,679,600	\$3,312,485
7	\$6,210,513	\$2,679,600	\$3,530,913
8	\$6,421,963	\$2,679,600	\$3,742,363
9	\$6,650,392	\$2,679,600	\$3,970,792
10	\$6,882,774	\$2,679,600	\$4,203,174
11	\$7,113,102	\$2,679,600	\$4,433,502
12	\$7,371,404	\$2,679,600	\$4,691,804
13	\$7,607,529	\$2,679,600	\$4,927,929
14	\$7,893,894	\$2,679,600	\$5,214,294
15	\$8,147,924	\$2,679,600	\$5,468,324
<b>Total</b>	<b>\$99,233,701</b>	<b>\$41,154,750</b>	<b>\$58,078,951</b>

Cost savings are based entirely on monthly meter reads.

Additional benefits from daily reads are realized in the areas of Customer Choice, Improved Reliability and Enhanced Operations.

# Meter Reading Services

**Customer Advanced Reliability System  
Base Operations - Meter Reading Services**

Year	Labor		Fringes		Transportation		Other		Indirect Costs	Estimated Costs	Benefits Eliminated Costs
	Existing	Future	Existing	Future	Existing	Future	Existing	Future			
Phase II	3,740,760	0	841,671	0	434,966	0	292,395	0	9,638	\$5,319,431	\$1,826,635
1	3,565,344	0	802,202	0	414,569	0	278,684	0	9,180	\$5,089,980	\$5,089,709
2	3,673,385	2,862	826,512	644	427,132	0	287,129	224	9,455	\$5,227,343	\$5,227,343
3	3,783,587	35,206	851,307	7,921	439,946	0	295,743	2,752	9,739	\$5,428,201	\$5,428,201
4	3,897,094	42,336	876,846	9,526	453,144	0	304,615	3,309	10,031	\$6,596,902	\$6,596,902
5	4,014,007	74,701	903,152	16,808	466,739	0	313,754	5,839	10,332	\$6,805,331	\$6,805,331
6	4,134,427	86,607	930,246	19,486	480,741	0	323,166	6,770	10,642	\$6,992,086	\$6,992,086
7	4,258,460	118,875	958,154	26,747	495,163	0	332,861	9,292	10,961	\$6,210,513	\$6,210,513
8	4,386,214	139,530	986,898	31,394	510,018	2,865	342,847	10,906	11,290	\$6,421,963	\$6,421,963
9	4,517,800	168,153	1,016,505	37,834	525,318	6,876	353,132	13,144	11,629	\$6,650,392	\$6,650,392
10	4,653,334	198,579	1,047,000	44,680	541,078	6,876	363,726	15,522	11,978	\$6,882,774	\$6,882,774
11	4,792,934	222,992	1,078,410	50,173	557,310	6,876	374,638	17,430	12,337	\$7,113,102	\$7,113,102
12	4,936,722	264,302	1,110,763	59,468	574,030	6,876	385,877	20,659	12,707	\$7,371,404	\$7,371,404
13	5,084,824	283,887	1,144,085	63,875	591,250	6,876	397,454	22,190	13,088	\$7,607,529	\$7,607,529
14	5,237,369	337,175	1,178,408	75,864	608,988	6,876	409,377	26,355	13,481	\$7,893,894	\$7,893,894
15	5,394,490	359,778	1,213,760	80,950	627,258	8,022	421,659	28,122	13,886	\$8,147,924	\$8,147,924
<b>Total</b>	<b>\$70,070,763</b>	<b>\$2,334,984</b>	<b>\$15,766,919</b>	<b>\$525,371</b>	<b>\$8,147,650</b>	<b>\$62,143</b>	<b>\$5,477,058</b>	<b>\$182,513</b>	<b>\$180,376</b>	<b>\$102,736,767</b>	<b>\$99,233,701</b>

**Assumptions / Definitions:**

- > Estimated costs will not be fully eliminated until after the first month of Phase III.
- > "Meter Reading Services" relates to activities that will be replaced by the Iron Service Agreement.
- > Replaced activities include, but are not limited to, the reading of single phase, demand and three phase meters.
- > Costs escalate annually based on inflation estimates.                      Inflation Rate    3.00%
- > "Fringes" are calculated as a percentage of labor costs.                      Fringes Rate:    22.50%
- > "Existing" costs relate to current staffing levels.
- > "Future" costs relate to increases in current staffing levels to handle meter growth. It is estimated that one person would be added for every 6,500 new meters.
- > "Other" costs include materials, overtime & fringes, and miscellaneous employee expenses.
- > "Indirect" costs include mailing expenses for letters and dial cards.



# **Customer Choice Pilot**

**Customer and Supplier Procedures**

**Release 1.1  
October 16, 1997**

# Customer Choice Pilot

## Customer and Supplier Procedures

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# Customer Choice Pilot

## Customer and Supplier Procedures

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### **I. Purpose**

The purpose of this document is to identify the interfaces with participating customers and suppliers and the procedures for transferring and communicating information.

### **II. Qualifying for the Duquesne Light Customer Choice Pilot Program**

Suppliers wishing to participate in Duquesne's Pilot Program must request participation and provide satisfactory documentary evidence of certification or licensure by the Pennsylvania Public Utility Commission (PUC). Requests and documentation should be sent to: Robert A. Irvin, General Manager, Duquesne Light Company, System Operations Unit, 2839 New Beaver Avenue, N2-SO, Pittsburgh, PA 15233.

Participating Suppliers who wish to purchase transmission service from Duquesne will need to execute a Service Agreement under Duquesne's Open Access Transmission Tariff.

### **III. Customer and Supplier Selection**

During the customer participation management process, several events can occur that will require communication and coordination with suppliers. These events are described below.

#### ***A. Identifying Selected Customers***

Once customers representing approximately five percent of Duquesne Light Company's non-coincident peak load have been randomly selected from the pool of customers that expressed interest in participating during the open enrollment, a file will be developed and made available to participating suppliers by Advantis mailbox. Information regarding Advantis is available by calling 1-800-727-2222. This ASCII file will contain the name, service address, mailing address, telephone number and customer type for each selected customer who did not expressly restrict the release of their information to suppliers. See *Appendix A for the Eligible Participants File description*.

In addition, this list of selected customers is available on a secure web site, [www.dlcpilot.lm.com](http://www.dlcpilot.lm.com), as of Monday, October 13, 1997, to PUC licensed suppliers only.

# Customer Choice Pilot

## Customer and Supplier Procedures

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### ***B. Changing from Duquesne to an Electricity Generation Supplier***

#### **1. Customer Oral Confirmation**

Duquesne will change a customer to an electricity supplier through direct oral confirmation with the customer if the customer is properly identified by:

- Name
- Address
- Social Security Number (if in the Duquesne customer record)
- Present Supplier (for initial change this will be Duquesne)
- Proposed Supplier
- Duquesne Account Number

#### **2. Customer Written Authorization**

Duquesne will change a customer to an electricity supplier through written evidence if the customer is properly identified by:

- Name
- Address
- Social Security Number (if in the Duquesne customer record)
- Present Supplier (for initial change this will be Duquesne)
- Proposed Supplier
- Duquesne Account Number

Note: The customer will be advised to use the form *in Appendix B - Customer/Supplier Agreement Document*.

#### **3. Supplier Contact**

Duquesne will change a customer who calls a supplier if the supplier immediately transfers the call to Duquesne so the change can be initiated. The electricity supplier may stay on the telephone for a three-way phone call.

- If the three-way phone call is unable to occur, the supplier will give the customer Duquesne's phone number so the customer can initiate the change.
- Alternatively, the supplier may acquire written authorization from the customer and provide this to Duquesne to initiate the change.

# Customer Choice Pilot

## Customer and Supplier Procedures

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Suppliers should use the form *in Appendix B - Customer/Supplier Agreement Document*.

### **4. Agent or Marketer Contact**

- The proposed regulations offer similar options to agents and marketers involved in the direct marketing of a supplier's services. One exception is that for supplier initiated contacts, immediate telephone transfers to Duquesne are prohibited. In this case, the customer would have to make direct contact with Duquesne to initiate the change.
- Valid written authorization from an agent or marketer is constituted by a document signed by the customer of record whose sole purpose is to obtain the customer's consent to change electric generation supplier. Such written authorization will result in Duquesne's initiation of the customer's request.

### **C. Customer Deselection**

Any customer participating in the Retail Pilot may "deselect" from further participation and return to Duquesne Light generation service at capped rates. Deselection must be authorized by the customer and processed by Duquesne subject to the adequate notice provisions to become effective as of the next scheduled meter reading date. These customers will not be readmitted into the Pilot.

### **D. Changing Customers to a New Generation Supplier**

Consistent with the above guidelines and subject to timely notification, Duquesne Light will switch the customer to the new supplier at the next scheduled meter reading date. Duquesne will assume that the customer has terminated the current supplier agreement and has the capacity to enter into a valid agreement with the new supplier.

### **E. Customer Electricity Supplier Status**

On a daily basis using the Advantis Mailbox, an ASCII file of each customer change in supplier, active or pending, will be delivered to each supplier. See *Appendix C, Customer Status File Format*, for the file definitions.

# Customer Choice Pilot

## Customer and Supplier Procedures

### IV. Billing

#### A. Consolidated Billing

##### 1. Supported Rate Structures

For the Retail Pilot, Duquesne Light will support a generation rate structure consisting of a single price per kWh, a single price per kW and a fixed monthly charge, or any subset of this structure.

##### 2. Providing Rate Information

Suppliers are to provide Duquesne Light with their rate structures. Set forth below is the rate structure supported by Duquesne for generation billing during the Retail Pilot. Rate schedules with greater complexity cannot be supported by Duquesne.

#### Supplier A Rate Plans

Supplier Rate Name	Price Per kWh	Price Per kW	Fixed Monthly Charge	Rate ID
XXXXXXXXXXXXXXXXXXXX	X.XX¢	\$XX.XX	\$XX.XX	XXXXX

Duquesne Light will establish a naming convention for the Rate ID with each supplier, including a rate class, e.g. residential. Each Rate ID must have a rate class. The Rate ID is a five digit alpha-numeric field. The first two fields will be alphabetic, will be unique to each supplier and will be assigned by Duquesne Light. The last three digits will be numbered according to the rate class:

- Residential Rates will be designated through the 100 number series, i.e., 100-199.
- Commercial Rates will be designated through the 200 number series, i.e., 200-299.
- Industrial Rates will be designated through the 300 number series, i.e., 300-399.

# Customer Choice Pilot

## Customer and Supplier Procedures

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The supplier will send by fax to Gwen Pielin at (412) 393-6119 or (412) 393-6157 the Supplier Rate Name, Price Per KWH, Price Per KW (if applicable) and the Fixed Monthly charge (if applicable). Duquesne Light will establish the naming convention for the Rate ID with each supplier as described above and communicate this to the supplier.

### 3. Processing Billing Data

For those customers who choose to receive one bill, Duquesne Light will calculate and bill both the Electric Distribution Company (EDC) and generation charges on the bill. The generation charge on the bill will be calculated in accordance with the rates provided to Duquesne Light by each supplier. Duquesne Light will provide each supplier with a file detailing the results of billing for their customers on a daily basis. These ASCII files will generally be in the suppliers' Advantis mailboxes by 6:00 AM the morning following calculation of the bills. *See Appendix D for the Billing Interface File.*

### 4. Bill Format

A consolidated customer bill will include one section for the EDC portion of the bill and a separate section for the supplier charges. The supplier's name will be presented at the top of the supplier section. The supplier's name and phone number will be presented in the message center. To avoid customer confusion, the pilot bills are formatted to closely resemble the current bills of Duquesne Light. *See Appendices E through G for Residential, Commercial and Industrial bill formats.*

### 5. Bill Messages

#### a) Required Messages

It is required that each supplier provide Duquesne Light with their customer service telephone number. This telephone number will be printed on consolidated bills in the message center.

#### b) Optional Messages

Duquesne Light will provide the suppliers with the ability to have up to four lines (forty-five characters each) of bill messaging subject to PA Public Utility Commission information requirements. Duquesne Light will support three levels of supplier messaging: global, revenue class and rate plan.

- **Global Messages** will appear on every bill produced for the supplier. For example, internet web site information.
- **Revenue Class Messages** will appear on every bill for the supplier in the designated revenue class.
- **Rate Plan Messages** will appear on every bill for the supplier in the designated rate plan.

This messaging functionality provides each supplier with the ability to target messages to specific groups of customers, subject to the appropriate approved Codes of Conduct.



# Customer Choice Pilot

## Customer and Supplier Procedures

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### **6. PaPUC Chapter 56 Regulations**

EDCs and suppliers are required to comply with the Chapter 56 regulations unless a specific waiver is requested by the EDC or a supplier and approved by the Pa PUC.

Duquesne Light's consolidated billing processes are designed to comply with Chapter 56.

### **7. Account Balance and Budget Billing**

For residential customers who choose consolidated billing, Duquesne Light will provide both account balance and budget billing for both the EDC and the supplier portions of the bill. See *Appendix E, Residential Consolidated Bill Format*.

#### **a) Actual Balance Billing**

For bill presentation purposes, the following rules will determine what appears in the account balance box on the bill:

- If the account is an actual balance customer, i.e., the customer regularly pays the account balance:
  - If both the Duquesne Light account balance and the supplier account balance are debits, the sum of the two balances will be printed in the account balance (amount due) box
  - If either the Duquesne Light actual balance or the supplier account balance is a credit, but the other is a debit, the debit balance amount will be printed in the account balance (amount due) box
  - If both the Duquesne Light account balance and the supplier account balance are credits, "NONE" will be printed in the account balance (amount due) box

#### **b) Budget Billing**

The supplier budget amount will be determined by applying the budget kWh as determined by the Duquesne Light budget billing process through the applicable supplier's schedule.

For bill presentation purposes, the following rules will determine what appears in the budget box on the bill:

- If it is the account anniversary date, the sum of the Duquesne Light and supplier actual balances will be printed in both the actual and budget boxes
- If the account is a budget customer, i.e., the customer regularly pays the budget amount:
  - If both the Duquesne Light budget balance and the supplier budget balance are debits, the sum of the two balances will be printed in the budget box

# Customer Choice Pilot

## Customer and Supplier Procedures

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- If either the Duquesne Light budget balance or the supplier budget balance is a credit, but the other is a debit, the debit balance amount will be printed in the budget box
- If both the Duquesne Light budget balance and the supplier budget balance are credits, "NONE" will be printed in the budget box

### **8. Estimated Meter Reading and Billing**

Duquesne reads meters for billing purposes on a monthly basis using predetermined schedules. Duquesne will generate estimated readings based on historical usage when the customer's bill cycle closes and no acceptable actual reading(s) is available.

For consolidated billing, estimated readings will be used to calculate both the EDC and generation charges on the bill. For separate billing, the estimated reading data will be passed to the appropriate supplier so they can perform their bill calculation.

### **B. Separate Billing by the Electricity Supplier**

#### **1. Providing Billing Determinants**

Duquesne Light Company will provide metering services for all customers participating in the pilot program. All meter readings will continue to be subjected to the existing validation routines. Readings will not be forwarded to suppliers until they have been successfully posted in Duquesne's customer information system. If readings are not successfully posted before the billing cycle closes, estimated readings will be generated by and provided to the suppliers.

For those customers who elect to receive separate bills (one from Duquesne Light Company and one from the supplier), a file will be built for each supplier containing the billing determinants that will be required by each supplier to calculate their bills. See *Appendix D for a description of the Billing Interface File.*

Monthly meter readings for pilot customers will be provided by Duquesne Light Company to generation suppliers for their customers in accordance with the existing Duquesne Light meter reading and billing cycles. Duquesne will provide total kWh and total kW consumption data to suppliers for each of their separately billed customers for whom such data are available. These reading data will be either actual or estimated. This information will be available to suppliers the morning after Duquesne calculates the EDC portion of the bill.

Each participating supplier will be requested to maintain an Advantis mailbox to facilitate the transfer of ASCII files between Duquesne Light Company and suppliers. These ASCII files generally will be in the suppliers' Advantis mailboxes by 6:00 AM the morning following the calculation of the EDC portion of the bill. Duquesne generates bills and processes payments on business days, Monday through Friday, excluding

# Customer Choice Pilot

## Customer and Supplier Procedures

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company holidays. Files will be provided to suppliers on Tuesday through Saturday. Using this information, each supplier will calculate the generation portion of the bill in accordance with their rates. See *Appendix K for Company holidays*.

### **V. Payment Processing**

#### **A. Partial Payment Order of Extinguishment**

During the pilot, the following partial payment allocation order of extinguishment will be utilized:

- First, Duquesne Light utility receivables will be extinguished<sup>1</sup>
- Second, supplier receivables will be extinguished
- Third, any residual will be applied to the Duquesne Light Company utility receivable balance and a credit balance will result.

Any deviation from this priority will require written instructions from the customer as required by Chapter 56.

If multiple supplier balances are outstanding, i.e., the customer has switched suppliers at least once and has an arrearage with more than one supplier, the supplier portion of the payment allocation will be applied to the oldest supplier balance first. Any residual supplier payment allocation will be applied to remaining supplier balances oldest to newest.

**Note: It will not be possible for a supplier balance to become a credit balance as a result of payment processing, with the exception of customer directed payments. However, an account can achieve a credit supplier balance as a result of a corrected bill or payment adjustment/correction.**

#### **B. Providing Payment Data to Suppliers**

For customers who have selected consolidated billing, Duquesne Light will process cash for suppliers during the pilot. Suppliers will be provided with a daily transaction file detailing payments received in an ASCII format. These files generally will be in the suppliers' Advantis mailboxes by 6:00 AM the morning following the processing of the payments. See *Appendix H for the Payment Processing Interface file*.

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<sup>1</sup> If the customer has an active payment arrangement with Duquesne Light Company, instead of extinguishing the account's total outstanding balance, an amount sufficient to meet the payment arrangement will be applied to the Duquesne Light Company payment arrangement balance.

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### **C. Returned Checks**

When a check is returned by the bank for any reason, the check amount will be reversed. The reversal will be posted to Duquesne Light Company receivables and supplier receivables in the same manner as the payment was originally applied.

Returned checks will be included as debit transactions in the daily transaction file described above.

### **D. Payment Corrections**

In the event that a payment is misapplied, the payment will be reapplied by Duquesne Light's Customer Accounting Department. Such payment corrections will be included in the daily transaction file described above.

### **E. Disbursement Of Collected Payments**

On a daily basis, Duquesne Light will generate a report showing payments received, returned checks, corrections and adjustments for each supplier. The report will net these amounts, resulting in the amount to be disbursed to each supplier. Duquesne Light's Electronic Commerce Department will receive this report and disburse cash accordingly. The method of disbursement will be determined by the Electronic Commerce Department on a supplier by supplier basis, e.g., check, wire transfer, ACH, EDI, etc.

## **VI. Reconciling Customer Receivables - Duquesne Light Company to Suppliers**

As described previously, Duquesne Light Company will provide each supplier with a daily ASCII file containing payment, returned check, correction and adjustment data. This file will contain a header and a trailer record. The trailer record will contain various control totals. Among these control totals will be the total number of records and the sum of the transaction amounts. Suppliers should verify that the file actually contains the number of records and the total amount indicated on the trailer record.

The trailer record will also contain the sum of all the supplier's actual account balances. The supplier should sum the actual balances for all Duquesne Light accounts on their system and reconcile this sum to the amount on the trailer record. Any discrepancies should be reported to the Supervisor of Billing and Accounts Receivable at (412) 393-6169 or (412) 393-6106.

# Customer Choice Pilot

## Customer and Supplier Procedures

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### VII. Taxes

#### A. *Unbundled Billing*

##### 1. Consolidated Billing

Each supplier must ensure that they (1) properly reflect the recovery of taxes in their rates provided to Duquesne and (2) properly collect and remit such taxes to the appropriate taxing authority. The taxes to be included are itemized below.

##### a) **PA State Sales Tax**

- The PA State Sales Tax that applies to the supplier portion of the bill will be presented in the "Sales Tax" line item in the supplier portion of the bill which includes both PA State and Allegheny County Sales Tax
- Tax rate is 6 percent
- PA State Sales Tax calculated for the supplier portion of the bill will be passed to the supplier in the billing interface file
- The exemption percentage will be applied to both the Duquesne Light and supplier portions of the bill

##### b) **Allegheny County Sales Tax**

- The Allegheny County Sales Tax that applies to the supplier portion of the bill will be presented in the "Sales Tax" line item in the supplier portion of the bill which includes both PA State and Allegheny County Sales Tax
- Tax rate is 1 percent
- Allegheny County Sales Tax calculated for the supplier portion of the bill will be passed to the supplier in the billing interface file
- The exemption percentage will be applied to both the Duquesne Light and supplier portions of the bill

##### c) **PA Gross Receipts Tax (GRT)**

- Required by Chapter 56
- This will continue to be detailed only on residential bills
- The sum of Duquesne Light Company and supplier PA Gross Receipts Tax will be presented in the "Estimated Gross Receipts Tax" box on the bottom of the bill.
- Suppliers must include PA Gross Receipts Tax in their rates, i.e., Duquesne Light Company will **not** calculate GRT and apply it to the supplier portion of the bill, or, "gross up" the GRT rate to recover the surtax portion.

# Customer Choice Pilot

## Customer and Supplier Procedures

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- GRT will be calculated in the following manner:  
Calculated as 4.4 percent of the bill as follows:
  - Supplier GRT = Supplier Bill Amount (including GRT in rates, but excluding sales taxes) \* 4.4 percent
  - or Supplier GRT = Supplier Bill Amount (excluding GRT and sales taxes) \* 4.6 percent.
- The PA Gross Receipts Tax calculated for the supplier portion of the bill will be passed to the supplier through the billing interface file

### d) **Estimated PA State Taxes**

- Estimated PA State Taxes will be calculated in the following manner:
  - Supplier Estimated PA State Taxes = Supplier Bill Amount before taxes \* **Percentage Provided By Supplier** + Supplier Sales Tax (PA and Allegheny County)
- "Estimated PA State Taxes" represents all taxes paid to PA<sup>2</sup>
- Suppliers must include all PA State Taxes (other than sales tax) in their rates, i.e., Duquesne Light will **not** calculate them and apply them to the supplier portion of the bill
- The Estimated PA State Taxes calculated for the supplier portion of the bill will be passed to the supplier through the billing interface file

## 2. **Separate Billing**

Since Duquesne Light will not be generating bills or processing payments on behalf of any supplier for separately billed unbundled customers, Duquesne Light Company will have no obligation or responsibility for taxes associated with such bills.

### **B. Tax Responsibility**

The Electricity Generation Customer Choice and Competition Act, Section 66 Pa. Code Section 2809 (C) (1) states in part:

---

<sup>2</sup> Public utilities remit taxes including public utility realty tax (PURTA), corporate net income tax, gross receipts tax and capital stock tax to Pennsylvania. Due to the unique circumstances of each supplier, Duquesne cannot compute an effective tax rate for purposes of computing the Estimated PA State Taxes.

# Customer Choice Pilot

## Customer and Supplier Procedures

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### (C) Financial Responsibility.

(1) In order to ensure the safety and reliability of the generation of electricity in this Commonwealth, no energy supplier license shall be issued or remain in force unless the holder complies with all of the following:

(i) Furnishes a bond or other security approved by the Commission, in form and amount to ensure the financial responsibility of the electric generation supplier and the supply of electricity at retail in accordance with contracts, agreements or arrangements.

(ii) Certifies to the Commission that it will pay and, in subsequent years, has paid, the full amount of taxes imposed by articles II and XI of the act of March 4, 1971 (P.L.6, No.2), known as the tax reform code of 1971 and any tax imposed by this chapter.

(iv) Agrees that it shall be subject to all taxes imposed by the tax reform code of 1971 and any tax imposed by this chapter. Failure of an electricity supplier to pay a tax referred to in this paragraph or to otherwise comply with the provisions of this paragraph shall be cause for the Commission to revoke the license of the electricity supplier.

As discussed previously, suppliers should ensure that their rates recover all appropriate taxes, including, but not limited to, Gross Receipts, Public Utility Realty (PURTA), Allegheny County and any future tax that may be passed by the state legislature. As indicated previously, Pennsylvania Sales tax is a separately itemized charge.

To ensure such taxes have been paid, Duquesne Light reserves the right to secure independent verification of compliance by any supplier with the requirements of the appropriate taxing authorities. Duquesne Light will use any and all appropriate legal remedies to recover any tax and related interest and penalties and costs of collection which it must pay or incur on behalf of any supplier.

### **VIII. Collection of Unpaid and Overdue Amounts (Draft)**

For customers who select a single, consolidated bill, their electricity generation provider will be responsible for collecting any unpaid and overdue amounts for generation service. Payment arrangements are a method of collecting unpaid and overdue amounts, and therefore, for customers who elect to receive a single, consolidated bill, any such arrangements are the responsibility of the supplier.

# Customer Choice Pilot

## Customer and Supplier Procedures

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For those customers who elect separate billing, i.e., to receive two bills per month, the supplier that bills their generation charges will be responsible for collecting unpaid and overdue amounts. As described previously, Duquesne will provide billing and payment data sufficient to allow suppliers to collect unpaid and overdue amounts from their customers.

### **IX. Customer Service**

#### **A. Customer Billing Inquiries**

Duquesne Light Customer Service Representatives (CSR) will attempt to resolve general questions pertaining to the supplier's portion of the bill when contacted by a customer. If the Duquesne Light CSR is unable to satisfy the customer's inquiry, the customer will be directed to contact the supplier at the telephone number indicated on the face of each bill.

#### **B. Disputes & Dispute Resolution<sup>3</sup>**

##### **1. Calls received by Duquesne Light Company**

###### **a) Consolidated Billing Inquiries**

All customer inquiries and disputes received by Duquesne Light will be processed by Duquesne Light. Duquesne Light will attempt to answer all customer inquiries during the first phone call. If the inquiry cannot be resolved, Duquesne Light will initiate a dispute and notify the supplier<sup>4</sup>. The supplier must be notified in order to suspend all appropriate collection activity as identified in Chapter 56. Electriccheck payments will be stopped until the dispute is closed. Duquesne Light will then investigate the dispute to determine what corrective action is required, if any. Corrective action may need to be taken by Duquesne Light, the supplier or both. Once appropriate action has been taken, the customer will be notified, the supplier will be notified and the dispute will be closed in accordance with the provisions of Chapter 56. See Appendix I for a flowchart of the dispute process for consolidated billing customers.

- Duquesne Light Billing Disputes
  1. Notify customer

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<sup>3</sup> Chapter 56 dictates a 10 day waiting period. This means that collection activities (Duquesne Light and supplier) may be suspended for up to 40 days.

<sup>4</sup> During the pilot, a daily list of opened and closed disputes will be mailed or faxed to the supplier by the Duquesne Light Company Customer Dispute Coordinator. This list will include all disputes opened or closed on the preparation date for accounts currently supplied by the supplier regardless of billing option (separate or consolidated).

# Customer Choice Pilot

## Customer and Supplier Procedures

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2. Record the resolution in the customer record and close the dispute
  3. Include in the daily list of opened and closed disputes which will be mailed or faxed to each supplier by the Duquesne Light customer dispute coordinator
- Supplier Billing Disputes
    1. Duquesne Light will notify customer
    2. The CSR will report the dispute to the Duquesne Light customer dispute coordinator
    3. The dispute will be recorded in the customer record.
    4. The Duquesne Light customer dispute coordinator will mail or fax the *dispute report to the supplier*
    5. The dispute will be listed on the daily list of opened and closed disputes which will be mailed or faxed to the supplier by the Duquesne Light customer dispute coordinator
    6. The supplier will resolve the dispute and notify the customer and Duquesne Light customer dispute coordinator
    7. Duquesne Light will record the resolution in the customer record and close the dispute.
    8. The dispute will be included in the daily list of opened and closed disputes which will be mailed or faxed to the supplier by the Duquesne Light customer dispute coordinator
  - Common (Duquesne Light and Supplier) Billing Disputes  
The process is the same as that for Duquesne Light billing disputes.

### **b) Separate Electricity Supplier Billing Inquiries**

All customer inquiries and disputes received by Duquesne Light will be processed by Duquesne Light. Duquesne Light will attempt to answer all customer inquiries during the first phone call. Customer inquiries or disputes directly related to the electricity supplier bill will be recorded but referred to the electricity supplier for handling. All other inquiries or disputes will be managed by Duquesne Light. For those calls being handled by Duquesne Light, if the inquiry cannot be resolved, Duquesne Light will initiate a dispute and notify the supplier<sup>5</sup>. The supplier must be notified in order to suspend all appropriate collection activity as identified in Chapter 56. Duquesne Light will then investigate the dispute to determine what corrective action is required, if any. Corrective action may need to be taken by Duquesne Light, the supplier or both. Once appropriate action has been taken, the customer will be notified, the supplier will be notified and the dispute will be closed in

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<sup>5</sup> During the pilot, a daily list of opened and closed disputes will be mailed or faxed to the supplier by the Duquesne Light Company Customer Dispute Coordinator. This list will include all disputes opened or closed on the preparation date for accounts currently supplied by the supplier regardless of billing option (separate or consolidated).

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accordance with the provisions of Chapter 56. See Appendix J for a flowchart of the dispute process for separate billing customers.

### **2. Inquiries from customers received by suppliers**

#### **a) Consolidated Billing Inquiries**

Inquiries related to the charges for generation and related payments will be addressed by suppliers. Any other inquiries must be referred to Duquesne Light at 1-888-393-7100.

#### **b) Separate Billing Inquiries**

Any inquiry related to the demand and consumption billed should be referred to Duquesne Light at 1-888-393-7100.

## **X. Advanced Metering Equipment**

Customers may acquire, at their expense, advanced metering equipment for measurement of consumption and demand provided that :

- The equipment is consistent with Duquesne's metering and communication infrastructure and
- The metering equipment provides data sufficient to meet Duquesne's needs for load scheduling, supplier settlement and billing.

Due to processing constraints, Duquesne may not be able to use the additional data available from advanced metering equipment during the Retail Pilot.

## **XI. Cancellation Of Service**

Customer participation in the pilot will be terminated upon cancellation of service. Customers who have had their pilot participation terminated as a result of cancellation of service may re-register for possible participation at their new location in the event Duquesne Light needs to re-solicit our customer base for additional participants at a later date. Suppliers will be made aware of customer cancellations through the billing interface file. All cancellations of service result in a final bill. Receipt of a final bill transaction in the billing interface file will indicate a cancellation of service to the supplier. Due to processing requirements a supplier may not be notified of a customer termination of service for seven days in disconnect for non-payment situations.

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### **XII. Customer Assistance Program (CAP) Customers**

CAP customers who wish to participate in Duquesne Light's customer choice pilot will be billed manually.

1. The CAP coordinator and Customer Accounting will maintain a list of the CAP customers who are participating in the pilot.
2. Customer Accounting will manually calculate the Duquesne Light portion of the unbundled bill (T, D, G%).
3. If the customer has selected consolidated billing, Customer Accounting will manually calculate the supplier portion of the unbundled bill.
4. The CAP coordinator will manually prepare a comprehensive bill including the unbundled Duquesne Light and supplier amounts. These amounts will be provided by Customer Accounting. This comprehensive bill will inform the customer of the total amount due and will contain a coupon with no scan line.
5. For separate billing customers, Customer Accounting will fax the customer's consumption to the supplier.
6. For consolidated billing customers, Customer Accounting will fax the billing and payment information to the supplier to provide them with information to manually update their accounts receivable systems.

### **XIII. Supplier Settlement Process**

#### ***A. Background***

The supplier settlement process in its simplest form is aimed at determining the amount of load attributable to each customer and thus each retail supplier on an hourly basis, and then reconciling these determinations with actual metered customer load and supplier delivery schedule as they become available. The process involves the matching of each supplier's hourly delivery schedule of electricity to the estimated hourly consumption of that supplier's customers, and settling the MWH electricity imbalance. This process requires a reconciliation of data from many sources, as well as the necessary time to collect and process these data.

#### ***B. Guiding Principles Underlying Duquesne Light's Approach***

Duquesne Light's general approach is to derive the supplier obligations based on the best information available given the current technology, and within the constraints of the pilot implementation schedule.

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Duquesne Light will use representative customer class load shapes, keeping careful records, and reconciling as much as possible with actual meter readings. Duquesne Light will use *actual daily meter readings for residential customers and hourly load profile meters* on a representative sample of Duquesne's customers:

- Daily consumption available for some customers. To the maximum extent practical, Duquesne Light will make use of a new wireless metering service currently being installed on its system. This system will facilitate the measurement of actual customer usage on a daily basis during the pilot. For other residential customers for whom the wireless metering system is not available, and all commercial and industrial customers in the pilot program Duquesne Light will have their meters read on a cyclical monthly basis.
- Representative hourly load profiles based on sample metering data. Furthermore, Duquesne Light plans to use contemporaneous kilowatt-hour readings from existing hourly load profile meters to develop representative load shapes for pilot customers. These special meters are located throughout Duquesne Light's service territory and provide hourly data for a sample of residential, commercial and industrial customers. If these data are not available during the early stage of the pilot, Duquesne will use historical hourly load profiles from 1996.

The combination of the new wireless metering service for some customers and a representative sample of contemporaneous hourly load profiles will increase the accuracy of Duquesne Light's settlement process. The difference between retail supplier delivery schedule and customer load in every hour will be multiplied by the energy imbalance rates.

### ***C. Major Steps***

1. Electricity suppliers submit schedules to System Operations. Suppliers will submit informational schedules on a week-ahead basis and submit formal schedules on a day-ahead basis.
2. Create representative load profiles for each customer class. Reading the load profile meters for representative customer accounts will provide a sample of hourly kilowatt-hour consumption patterns. These hourly load profiles will be developed for each customer class.
3. Read customer meters. This will result in actual daily kilowatt-hour meter readings for the residential customers with new wireless meters, and monthly kilowatt-hour consumption for other residential customers, and all commercial and industrial customers.

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4. Estimate customer usage by supplier. Using the estimated load shapes for each customer class, and the meter readings described above, the amount of retail load for each supplier will be estimated.<sup>6</sup>
  - Aggregate kilowatt-hour readings by customer class for each supplier. For residential customers with wireless meters, these will be daily kilowatt-hour figures, and for all customers these will be monthly figures.
  - Apply hourly load profiles to each rate class for each supplier. The estimated load profile for each rate class will be used to derive the estimated hourly consumption. These hourly kilowatt-hour figures by rate class will be summed for each supplier to determine that supplier's estimated MW hourly load obligation.
5. Calculate energy imbalance for each supplier. Energy imbalances will be settled with each supplier in accordance with Open Access Transmission Tariff of the Duquesne Light Company filed July 9, 1996 at FERC Docket ER 96-2573-000 (also referenced at OA 96-56-000), as amended.

Due to constraints inherent in the collection of meter readings on a billing cycle basis, the supplier settlement process is expected to lag the calendar month by at least thirty-five days.

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<sup>6</sup> Estimated usage by supplier for each hour will not be aggregated and reconciled to the total system load during the Retail Pilot. This reconciliation will be performed during the Transition Period.

## **xiv. Appendices**

## A. Appendix A - Eligible Participants File

### Header

No.	Field Name & Description	Starting Position	Length	Type	Comments
1	BEGIN-KEY (sorting value) Spaces	1	15	A	
2	EXTRACT-PARM Value S = Supplier	16	1	A	
3	FILLER	17	94		
4	CREATE-DATE	95	10	A	
5	FILLER	105	122	A	
6	SORT-SUM-FLD-BREC Value 0	227	1	N	Check for duplication

### Data Record

No.	Field Name & Description	Starting Position	Length	Type	Comments
	DATA RECORD				
1	ACCOUNT-NO	1	13	N	The customer DLCo account number.
2	CUST-NAME Name of customer associated with the account	14	26	A	Last Name X(15) First Name X(10) Middle Initial X(01)
3	CODE-NAME-TYPE How the name is formatted	40	1	A	A - a business name B - an individual name (last name, first name, middle initial)
4	CUST-NAME-2 The second name of an address.	41	26	A	May consist of : a person's name; a company name or a location name.
5	CODE-NAME-TYPE-2 How the name is formatted	67	1	A	A - a business name B - an individual name (last name, first name, middle initial)
6	CUST-TYPE Code that indicates type of customer.	68	1	A	R - residential C - commercial I - industrial
7	CUST-PHONE-NO Consists of premise phone number	69	10	A	

Appendix A - Eligible Participants File Format - continued

No.	Field Name & Description	Starting Position	Length	Type	Comments
8	<b>CUST-ADDRESS-LN1</b> Consists of premise street address	79	33	A	This field will contain the first line of the premise street address, and will consist of the following fields: House Number X(05) Space X(01) Address Prefix1 X(03) Space X(01) Address Prefix2 X(02) Space X(01) Street Name X(16) Space X(01) Street Suffix X(03)
9	<b>CUST-ADDRESS-LN2</b> Contains the 2 <sup>nd</sup> line of the premise street address & will contain apt/bldg info when applicable.	112	9	A	This field will consist of the following fields: AddressLocation1 X(04) Space X(01) AddressLocation2 X(04)
10	<b>CUST-ADDRESS-CITY</b> This field will contain the city in which the premise is located.	121	16	A	
11	<b>CUST-ADDRESS-STATE</b> This field will contain the 2 digit state code in which the premise is located.	137	2	A	
12	<b>CUST-ADDRESS-ZIP</b> This field will contain the 5 digit zip code and the plus 4 in which the premise is located.	139	9	N	
13	<b>MAILING-ADDRESS</b> This field will contain the alternate mailing street address when applicable.	148	35	A	This address is different from the premise address and is where the bill and any DLCO material is sent.
14	<b>MAILING-CITY-STATE</b> This field will contain the alternate city & state.	183	20	A	
15	<b>ZIP-CODE</b> This field will contain the alternate Zip Code.	203	9	N	
16	<b>KWH-LAST-12-MTHS</b>	212	9	N	The sum of the accounts kWh's for the last 12 bills.
17	<b>PEAK-KW-LAST-12-MTHS</b>	221	6	N	The account's peak demand over the last 12 bills.
18	<b>SORT-SUM-FLD</b> Value 0	227	1	N	Checks for duplication

Appendix A - Eligible Participants File Format - continued

**Trailer**

No.	Field Name & Description	Starting Position	Length	Type	Comments
	<b>DATA RECORD TRAILER</b>				
1	<b>END-KEY</b> 99 99 99 99 99 99 99 9	1	15	A	
2	<b>FILLER</b>	16	11	A	
3	<b>RECORD-COUNT-EREC</b> Count of detail records excluding header & trailer.	27	7	N	
4	<b>FILLER</b>	34	169		
5	<b>FILLER</b>	203	196		
6	<b>SORT-SUM-FLD-EREC</b> Value 0	399	1	N	Checks for duplication.

**B. Appendix B - Customer/Supplier Agreement Document**

**DUQUESNE LIGHT COMPANY  
CUSTOMER/SUPPLIER AGREEMENT**

**Customer Information**

Duquesne Light Company Account Number														
					-									

Name (Last Name, First Name, Middle Initial)																									

Daytime Phone Number									

Evening Phone Number									

**Customer Service Address**

House Number				

Street Name																								

Apt # or Flr Location				

City														

State	

Zip Code									

**Mailing Address** *(Leave blank if same as Service Address)*

Street																								

--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

City														

State	

Zip Code									

**Generation Supplier Data**

Supplier Name																								

Supplier Rate				

Please check the type of billing you would like to receive. Do NOT check both.																								
One bill each month from Duquesne Light																								
Two bills each month - one from the supplier and one from Duquesne Light																								

Customer Signature: \_\_\_\_\_ (Date)

Authorized Supplier: \_\_\_\_\_ (Date)

*We have entered into an agreement containing the terms and conditions of an alternate electric power source. We understand that under Duquesne Light Company's Retail Pilot Program, billing will be rendered according to the rate and bill type selected above. Execution of this agreement cannot occur until this completed form is received and processed by Duquesne Light Company.*

Mailed this agreement to:  
Duquesne Light Company  
Customer Relations Department  
301 Grant Street (16-1)  
Pittsburgh, PA 15279

**C. Appendix C - Customer Status File Format**

**Data Record**

No.	Field Name & Description	Starting Position	Length	Type	Comments
1.	FILLER	1	1	A	Space
2.	SUPP-ID - Supplier-ID Unique identifier assigned by DLCO to a supplier	2	10	A	
3.	REC-TYPE	12	1	A	A = Header B = Detail C = Trailer
4.	ACCOUNT-NO - DLCO Account No. Identifies the intersection between a Customer and a Premise.	13	13	A	Composed of a 10 digit Customer ID number plus a 3 digit extension which is increased by one each time a customer moves to a new premise.
5.	DATE-START	26	10	A	CCYY-MM-DD
6.	DATE-TERM	36	10	A	CCYY-MM-DD
7.	CODE-CHOICE-STAT	46	2	A	AC Active CT Contract Terminated CC Customer Canceled MA Moved While Active MP Moved While Pending PS Pending Switch PA Pending Activation RB Returned To Bundled RU Return To Unbundled
8.	BILL-CYCLE	48	4	N	The account's bill cycle.
9.	READ-CYCLE	52	4	N	The account's meter reading cycle. This number can be correlated to the meter reading schedule to determine the account's scheduled read dates.
10.	REVENUE-CLASS	56	4	N	The account's revenue class.  401 Residential 421 Commercial (<20 kW) 425 Commercial (≥20 kW) 426 Industrial 441 Municipal Street Lights 471 Borough Of Pitcairn
11.	RATE-PLAN-NO	60	3	A	The account's DLCo rate plan.

Appendix C - Customer Status File Format - continued

12.	<b>SUPP-RATE-ID</b> The supplier rate associated with the account.	63	5	A	The account's supplier rate plan.
13.	<b>CUST-NAME</b> The name of the customer associated with the account.	68	26	A	
14.	<b>CODE-NAME-TYPE</b>	94	1	A	
15.	<b>CUST-ADDRESS-LN1</b> The premise street address.	95	33	A	This field will contain the first line of the premise street address, and will consist of the following fields: House Number X(05) Space X(01) Address Prefix1 X(03) Space X(01) Address Prefix2 X(02) Space X(01) Street Name X(16) Space X(01) Street Suffix X(03)
16.	<b>CUST-ADDRESS-LN2</b> The 2 <sup>nd</sup> line of the premise street address. Contains APT/BLDG info when applicable.	126	9	A	This field will consist of the following fields: Address Location X(04) Space X(01) Address Location 2 X(04)
17.	<b>CUST-ADDRESS-CITY</b> The city in which the premise is located.	137	16	A	
18.	<b>CUST-ADDRESS-STATE</b> The 2 digit state code identifying the state in which the premise is located.	153	2	A	
19.	<b>CUST-ADDRESS-ZIP</b> The 5 digit zip code and the plus 4 in which the premise is located.	155	9	N	
20.	<b>FILLER</b>	164	36	A	Spaces

Appendix C - Customer Status File Format - continued

**Header**

No.	Field Name & Description	Starting Position	Length <sup>3</sup>	Type <sup>4</sup>	Comments
1.	FILLER	1	1	A	Space
2.	HDR-SUPP-ID - Supplier-ID Unique identifier assigned by DLCO to a supplier.	2	10	A	
3.	HDR-REC-TYPE	12	1	A	A = Header B = Detail C = Trailer
4.	HDR-PROCESS-DATE	13	10	A	CCYY-MM-DD
5.	FILLER	39	161	A	Blanks

**Trailer**

	Field Name & Description	Starting Position	Length	Type	Comments
1.	FILLER	1	1	A	Space
2.	TLR-SUPP-ID - Supplier-ID Unique identifier assigned by DLCO to a supplier.	2	10	A	
3.	TLR-REC-TYPE	12	1	A	A = Header B = Detail C = Trailer
4.	TLR-REC-COUNT - Total number of detail records.	13	9	N	
5.	FILLER	22	178	A	Blanks

<sup>3</sup> Length - n.d represents whole number with decimal positions

<sup>4</sup> Type - A - alphanumeric & N - numeric (all numeric types are signed numbers)

## Appendix C - Customer Status File Format - continued

Duquesne Light will provide each supplier with a file detailing accounts that have left the supplier, joined the supplier or are pending a switch to the supplier on a daily basis. These files will generally be in the suppliers' Advantis mailboxes by 6:00 AM the morning following Duquesne's nightly batch processing.

This file will be a major component of a supplier's load scheduling process. At a high level, suppliers should:

- stop scheduling load for accounts that have left
- start scheduling load for accounts that have joined
- begin projecting load requirements for accounts that are pending a switch to the supplier.

This file will identify each account's DLCo read cycle and DLCo rate plan. These two pieces of information will play a critical role in the suppliers' load scheduling activities. For accounts that are pending a switch to the supplier, the read cycle can be used to determine the scheduled read date for the account. This is the date on which the account will most likely begin taking power from the supplier. Therefore, this is the date on which the supplier should begin scheduling load for this account. By providing the rate plan for each account, the supplier will be able to associate each account to a load profile in order to determine the appropriate amount of hourly load to schedule.

**D. Appendix D - Billing Interface File**

No.	Field Name & Description	Starting Position	Length <sup>5</sup>	Type <sup>6</sup>	Comments
1	HDR-SORT-KEY	1	50	F	No Data Supplied
2	HDR-DISTRIB Distribution company ID.	51	4	A	'DLCO'
3	HDR-SUPP-ID (Supplier-ID) Unique identifier assigned by DLCO to a supplier.	55	10	A	Supplier can confirm receipt of appropriate files by matching to assigned ID.
4	HDR-CODE-BILL-METHOD	65	1	A	
5	HDR-CODE-BILL-OPTION	66	1	A	
	<b>DATA HEADER</b>				
5	HDR-DT-BILLED (Date-Billed) Date bill was generated & receivables posted.	67	10	A	ccyy-mm-dd
6	HDR-TRANS-DT (File Creation Date) Date file created that will be sent to suppliers.	77	26	A	Timestamp ccyy-mm-dd- hh.mm.ss.xxxxxx
7	Filler	103	598	A	

**Data Record**

No.	Field Name & Description	Starting Position	Length	Type	Comments
	<b>DLCO KEY</b>				
1	PREMISE-NO This number is a unique DLC identifier for the premise where service is provided.	1	10	N	
2	BILL-NO Sequential bill number from DLCO system.	11	9	N	Only unique within premise.
3	CODE-UTIL-TYPE (Utility Type Code) Type of Service Code	20	1	A	E - metered U - unmetered
4	IC-NO	21	4	N	
5	BILL-ITEM-TIMESTMP Date and time item was created.	25	26	A	Format: ccyy-mm-dd- hh.mm.ss.xxxxx
6	DISTRIB-ID Distribution company ID.	51	4	A	'DLCO'
7	SUPP-ID Unique identifier assigned by DLCO to a supplier.	55	10	A	

<sup>5</sup> Length - n.d represents whole number with decimal positions

<sup>6</sup> Type - A - alphanumeric & N - numeric (all numeric types are signed numbers)

Appendix D - Billing Interface File - continued

No.	Field Name & Description	Starting Position	Length	Type	Comments
	<b>SORT KEY</b>				
8	<b>CODE-BILL-METHOD</b> Method of Bill Calculation.	65	1	A	T - Passthru C - Complete Billing Service
9	<b>CODE-BILL-OPTION</b> Customer's billing option.	66	1	A	S - Separate I - Integrated
	<b>DLCO BILLING DATA</b>				
10	<b>SUPP-ACCT-NO</b> The number assigned to the account by the supplier.	67	20	A	A stand alone field with a relationship to one & only one DLCO Account No.
11	<b>ACCOUNT-NO (DLCO)</b> Identifies the intersection between a Customer and a Premise.	87	13	N	It is composed of a 10 digit Customer ID number plus a 3 digit extension which is increased by one each time a customer moves to a new premise.
12	<b>CODE-BILL-TYPE</b> Type of bill generated.	100	1	A	A - Normal B - Final C - Charge Off D - Initial
13	<b>CODE-BILL-ITM-TYPE</b> Status of this bill item.	101	1	A	B - Backout C - Current
14	<b>CODE-COUNTY</b> Used for determination of additional 1% sales tax for Allegheny county customers only.	102	2	A	AL - Allegheny County WE - Westmoreland Cty. BE - Beaver County
15	<b>DATE-ORIG-BILL</b> The date of the original bill	104	10	A	Conditional - Only provided on backout bills (ccyy-mm-dd)
16	<b>DATE-CURR-READ (Date of Current Reading)</b>	114	10	A	ccyy-mm-dd
17	<b>DATE-PRIOR-READ</b>	124	10	A	ccyy-mm-dd
18	<b>NO-DAYS</b> Number of days for this bill.	134	4	N	Days between meter readings
19	<b>NO-MONTHS</b> Number of months for this bill.	138	5	N	
20	<b>KWH</b> Kilowatt-hour usage	143	9	N	
21	<b>OPT-KWH (Optional Kilowatt-Hour)</b> This field describes an alternate energy usage amount for use in determining a budget bill for residential customers.	152	9	N	The customer is given the option of paying either the standard bill based on actual or estimated meter reading(s) or the budget bill amount based on the calculated "Optional Kilowatt-Hour" usage amount.
22	<b>Actual KW (Demand)</b>	161	7.2	N	Used for Demand readings on account.

Appendix D - Billing Interface File - continued

No.	Field Name & Description	Starting Position	Length	Type	Comments
23	<b>ADJUSTED-KW</b> (Adjusted Demand Usage) The prevailing calculated demand amount used for bill pricing in situations where minimum demand, minimum charge based on demand, percentage of contracted demand, or maximum average charge pre-empt calculating the bill based on the actual metered demand usage.	170	7.2	N	If no Adjusted Demand Usage is available, the Actual Kilowatt Usage (actual metered demand usage) will be replicated into this field).
24	<b>CODE-READ-TYPE</b> Type of Meter Reading	179	1	A	A - Actual E - Estimated
25	<b>DATE-BILL-DUE</b> (Payment Due Date)	180	10	N	ccyy-mm-dd
<b>SUPPLIER DATA</b>					
26	<b>PRIOR-ACCT-BAL</b> Generation portion balance prior to execution of this bill.	190	9.2	N	Includes any payments and/or adjustments occurring since the last bill.
27	<b>AMT-LATE-PYMT-CHRG</b> Supplier determined late payment charge applicable to generation portion of the bill.	201	9.2	N	'Not used at present time.'
28	<b>AMT-ACCT-ADJMTS</b> Amount of any account receivable adjustments made to the supplier's portion of the account since the last bill was issued.	212	9.2	N	
29	<b>AMT-ACCT-PYMTS</b> Amount of any account receivable adjustment made to the supplier's portion of the account since the last bill was issued.	223	9.2	N	
30	<b>DATE-LAST-PYMT</b> Date the supplier portion of the payment was applied to account receivables.	234	10	A	ccyy-mm-dd
31	<b>AMT-CUST-CHRG</b> Flat account charge assessed by supplier.	244	9.2	N	
32	<b>AMT-KWH-CHRG</b> (Supplier Energy Charge) Dollar amount reflecting the charge for generation of energy.	255	9.2	N	
33	<b>AMT-KW-CHRG</b> (Supplier Demand Charge) Dollar amount reflecting the charge for generation of demand.	266	9.2	N	

Appendix D - Billing Interface File - continued

No.	Field Name & Description	Starting Position	Length	Type	Comments
34	<b>AMT-STATE-TAX</b> State tax amount applied to the generation portion of the customer's bill.	277	9.2	N	
35	<b>AMT-COUNTY-TAX</b> County tax(where applicable) amount applied to the generation portion of the customer's bill.	288	9.2	N	
36	<b>AMT-CURR-BILL</b> Total amount of current bill exclusive of any prior balances.	299	9.2	N	
37	<b>CURR-ACCT-BAL</b> New account balance including current & past due charges.	310	9.2	N	
38	<b>Optional Account Balance</b> New account balance for 'Budget Billing' charges including current & past due budget billing charges.	321	9.2	N	Budget billing charges are based on Optional KWH usage detailed in the DLCO Billing Data.
39	<b>OPT-CURR-AMT</b> Current month's 'Budget Billing' charges only.	332	9.2	N	
40	<b>EST-PA-TAXES</b> All utility state taxes.	343	9.2	N	Calculated the same way as for DLCO portion of the bill. (For bill presentation purposes not tax accounting.)
41	<b>EST-GROSS-RCPT-TAX</b> Gross Receipt Tax.	354	9.2	N	Calculated the same way as for DLCO portion of the bill. (For bill presentation purposes not tax accounting.)
42	<b>KWH-LTTR-OF-CR-DB</b> Energy usage amount affected by letter of credit or debit as applicable to the generation portion of the bill.	365	9	N	
43	<b>KW-LTTR-OF-CR-DB</b> Demand usage amount affected by letter of credit or debit as applicable to the generation portion of the bill.	374	7.2	N	

Appendix D - Billing Interface File - continued

No.	Field Name & Description	Starting Position	Length	Type	Comments
44	<b>AMT-LTTR-OF-CR-DB</b> Dollar amount affected by letter of credit or debit as applicable to the generation portion of the bill.	383	9.2	N	
45	<b>CODE-SUPP-RATE-ID</b> (Supplier) Internal code used to define the rate structure used for calculation of the generation portion of the bill.	394	5	A	(Format to be determined)
46	<b>CODE-REJECT</b> (Supplier) Code indicating type of reject that occurred when processing the Supplier's portion of the bill.	399	1	A	Space - No reject occurred. R - Account rejected within the generation billing system. K - Account rejected within the DLCO portion of the bill.
47	<b>BILL-MSG-1</b>	400	45	A	Messages 1 - 5 Actual supplier message(s) printed on the bill.
48	<b>BILL-MSG-2</b>	445	45	A	
49	<b>BILL-MSG-3</b>	490	45	A	
50	<b>BILL-MSG-4</b>	535	45	A	
51	<b>BILL-MSG-5</b>	580	45	A	
52	<b>DATE-CALCULATED</b> When Supplier portion of the bill processed.	625	26	A	Datestamp ccyy-mm-dd-hh.mm.ss.xxxxxx (Can differ from DLCO billing date).
53	<b>CODE-BILL-MSG</b>	651	5	A	
54	<b>PRI-BILL-ACCT-BAL</b> Supplier's prior account balance after the last bill.	656	9.2	N	NOT INCLUDING any payments and/or adjustments made to the supplier portion of the account balance since the last bill.
55	Filler	667	34	A	

Trailer

No.	Field Name & Description	Starting Position	Length	Type	Comments
	<b>DATA</b>				
1	<b>TLR-KEY</b>	1	50		
2	<b>TLR-DISTRIB-ID</b> Distribution company ID.	51	4	A	'DLCO'
3	<b>TLR-SUPP-ID</b> Unique identifier assigned by DLCO to a supplier	55	10	A	
4	<b>TLR-CODE-BILL-METHOD</b>	65	1	A	
5	<b>TLR-CODE-BILL-OPTION</b>	66	1	A	
6	<b>TLR-DT-BILLED</b> Date bill was generated & receivables posted.	67	10	A	ccyy-mm-dd
7	<b>TLR-TRANS-DT</b> (file creation date) Date file created that will be sent to suppliers.	77	26	A	Timestamp ccyy-mm-dd-hh.mm.ss.xxxxxx
8	<b>TLR-COUNT</b> Count of data records	103	7	N	
9	Filler	110	591	A	

**E. Appendix E - Residential Consolidated Bill Format**



**Duquesne Light**

H

CHOICE CUSTOMER  
123 MAIN ST

RATE (RSP) - Residential  
Service

Date Prepared  
Sep 01, 19XX

Account Number  
1000-123-456-001

**Duquesne Light Company Billing Information**

**Meter Read Information**

Present: Mar 1, 19XX - Actual      0500  
 Prior: Feb 1, 19XX - Actual      0000  
 Difference                              500  
 Your Meter Multiplier              X 1  
 Total kWh used                        500

**Prior Billing Information**

Amount Of Last DLCo Bill              \$XX.XX  
 Payment Received: Feb 15 - Thank You      -XX.XX  
**Amount Owed From Your Last DLCo Bill**      **\$X.XX**

**Current Charges**

Customer Distribution Charge              \$X.XX  
 Transmission Charge                      500 kWh @ X.XXX¢      X.XX  
 Distribution Charge                      500 kWh @ X.XXX¢      X.XX  
 Generation Charge                        500 kWh @ X.XXX¢      X.XX  
 Pennsylvania Tax Adjustment              X.XX  
 Customer Generation Credit              500 kWh @ X.XXX¢      -X.XX  
 Customer Participation Credit              -X.XX

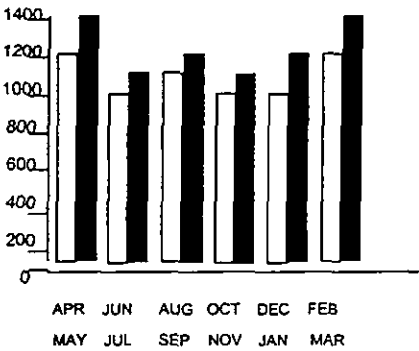
**Current DLCo Billing Charges**

Your Pledge To The Dollar Energy Fund      X.XX

**Total DLCo Account Balance**              **\$XX.XX**

**Electric Usage Bi-Monthly**

kWh



■ Prior 12 Months □ Latest 12 Months

**Message Center**

For questions regarding the Supplier ABC portion of the bill, please call 1-800-555-4567. Generation prices and charges are set by the generation supplier that you have chosen. The Public Utility Commission regulates retail transmission and distribution prices and services. For general information, please see the reverse side of this bill.

Your Total Taxes: About 14.3% of your total bill is for Federal, State and Local taxes.

**Supplier ABC Billing Information**

**Prior Billing Information**  
 Amount Of Last Supplier Bill              \$XX.XX  
 Payment Received: Feb 15 - Thank You      -XX.XX  
**Amount Owed From Your Last Supplier Bill**      **\$X.XX**

**Current Charges**

Usage: 500 kWh From Feb 1 To Mar 1              X.XX

**Total Supplier Account Balance**              **\$XX.XX**

**Total Amount Due**                              **\$XX.XX**

Estimated Gross Receipts Tax	Estimated PA State Taxes	Late charge after Mar 20, 19XX	PAYMENT DUE	BUDGET AMOUNT	AMOUNT DUE
\$X.XX	\$X.XX	\$X.XX	Mar 25, 19XX	\$XX.XX or	\$XX.XX

Please return this portion with your payment.

YOU MAY PAY EITHER AMOUNT

Account Number  
1000-123-456-001

SXX.XX

SXX.XX

Amount Enclosed \$

--	--	--	--	--	--



CHOICE CUSTOMER  
123 MAIN ST  
PITTSBURGH PA 15212-0884

10001234560011 000000000000 000000000000 000000000000

**F. Appendix F - Commercial Consolidated Format**



**Duquesne Light**

H SERVICE USED AT: 321 MAIN ST  
RATE GS/GMP - GENERAL SERVICE SMALL AND MEDIUM

DATE PREPARED  
SEP 01, 19XX

ACCOUNT NUMBER  
2000-654-321-001

TYPE OF SERV	SERVICE PERIOD		KILOWATT HOUR INFORMATION					KW DEMAND INFORMATION		
	FROM	TO	METER READINGS		DIFFERENCE	METER CONSTANT	KILOWATT HOURS	DEMAND READING	PWR. FACT. MULT.	BILLING DEMAND
			PRIOR	PRESENT						
P	02-08	03-10	3442	3465	23	480.0	11040	.08	1.00	38.40
L	02-08	03-10	0193	0387	194	12.0	2328	.93		11.20
										49.60

ACTUAL METER READING BILL TOTAL 13368

DUQUESNE LIGHT COMPANY BILLING INFORMATION				SUPPLIER ABC BILLING INFORMATION			
<u>PRIOR BILLING INFORMATION</u>				<u>AMOUNT OF LAST BILL</u> \$XXX.XX			
AMOUNT OF LAST DLCo BILL				PAYMENT - FEBRUARY 23			
AMOUNT OWED FROM YOUR LAST DLCo BILL				ACCOUNT BALANCE REMAINING			
PAYMENT - FEBRUARY 23				CHARGES FOR 02-08 THRU 03-10			
				KWH: 13368 KW: 49.6			
<u>CURRENT CHARGES</u>				PENNSYLVANIA SALES TAX			
CUSTOMER DISTRIBUTION CHARGE				CURRENT BILLING PERIOD AMT			
TRANSMISSION CHARGE-DEMAND 5 KW @ NO CHARGE				ACCOUNT BALANCE			
44.6 KW @ \$X.XX							
DISTRIBUTION CHARGE-DEMAND 5 KW @ NO CHARGE							
44.6 KW @ \$X.XX							
GENERATION CHARGE-DEMAND 5 KW @ NO CHARGE							
44.6 KW @ \$X.XX							
TRANSMISSION CHARGE-ENERGY 550 KWH @ X.XX¢							
750 KWH @ X.XX¢							
2068 KWH @ X.XX¢							
DISTRIBUTION CHARGE-ENERGY 550 KWH @ X.XX¢							
750 KWH @ X.XX¢							
2068 KWH @ X.XX¢							
GENERATION CHARGE - ENERGY 550 KWH @ X.XX¢							
750 KWH @ X.XX¢							
2068 KWH @ X.XX¢							
PENNSYLVANIA TAX ADJUSTMENT							
CUSTOMER GENERATION CREDIT 13368 KWH @ X.XX¢							
CUSTOMER PARTICIPATION CREDIT							
SALES TAX							
CURRENT DLCo BILLING CHARGES							
TOTAL DLCo ACCOUNT BALANCE							
				<u>MESSAGE CENTER</u>			
				FOR QUESTIONS REGARDING THE SUPPLIER ABC PORTION OF YOUR BILL, PLEASE CALL 1-800-555-4567.			
				GENERATION PRICES AND CHARGES ARE SET BY THE ELECTRIC GENERATION SUPPLIER THAT YOU HAVE CHOSEN. THE PUBLIC UTILITY COMMISSION REGULATES RETAIL TRANSMISSION AND DISTRIBUTION PRICES AND SERVICES.			
				FOR GENERAL INFORMATION, PLEASE SEE THE REVERSE SIDE OF THIS BILL.			
				TOTAL AMOUNT DUE			
				SXXXXX.XX			

EST. PA STATE TAXES	LATE PYMT CHARGE RATE PER MONTH	PAYMENT DUE	DLCo AMOUNT	SUPPLIER AMT	TOTAL AMT DUE
\$XXX.XX	1.25%	MAR 28 'XX	\$XXX.XX	\$XXX.XX	\$XXXXX.XX

Please return this portion with your payment.

\$XXXXXX.XX

ACCOUNT NUMBER  
2000-654-321-001

Amount Enclosed \$

--	--	--	--	--	--

COMMERCIAL CHOICE CUSTOMER  
321 MAIN ST  
PITTSBURGH, PA 15212-0084

2000654321001 000000000000 000000000000 000000000000

**G. Appendix G- Industrial Consolidated Bill Format** *(not available at this time)*

## H. Appendix H - Payment Processing Interface File

### Data Record

No.	Field Name & Description	Starting Position	Length	Type	Comments
1.	<b>SUPP-ID</b> - Supplier-ID Unique identifier assigned by DLCO to a supplier	1	10	A	
2.	<b>REC-TYPE</b>		1	A	A = Header B = Detail C = Trailer
3.	<b>CODE-TRAN-TYPE</b>		1	A	P = Payments C = A/R Credits D = A/R Debits N = NSFS A = A/R Adjustments
4.	<b>ACCOUNT-NO</b> - DLCO Account No. Identifies the intersection between a Customer and a Premise.		13	A	Composed of a 10 digit Customer ID number plus a 3 digit extension which is increased by one each time a customer moves to a new premise.
5.	<b>DATE-TRANS</b>		10	N	ccyy-mm-dd
6.	<b>AMT-TRAN</b>		12	N	Contains two assumed decimal values.
7.	<b>FILLER</b>		107	A	Blanks

### Header

No.	Field Name & Description	Starting Position	Length <sup>7</sup>	Type <sup>8</sup>	Comments
1.	<b>HDR-SUPP-ID</b> - Supplier-ID Unique identifier assigned by DLCO to a supplier.	1	10	A	
2.	<b>HDR-REC-TYPE</b>		1	A	A = Header B = Detail C = Trailer
3.	<b>HDR-PROCESS-DATE</b>		10	A	ccyy-mm-dd
4.	<b>FILLER</b>		129	A	Blanks

<sup>7</sup> Length - n.d represents whole number with decimal positions

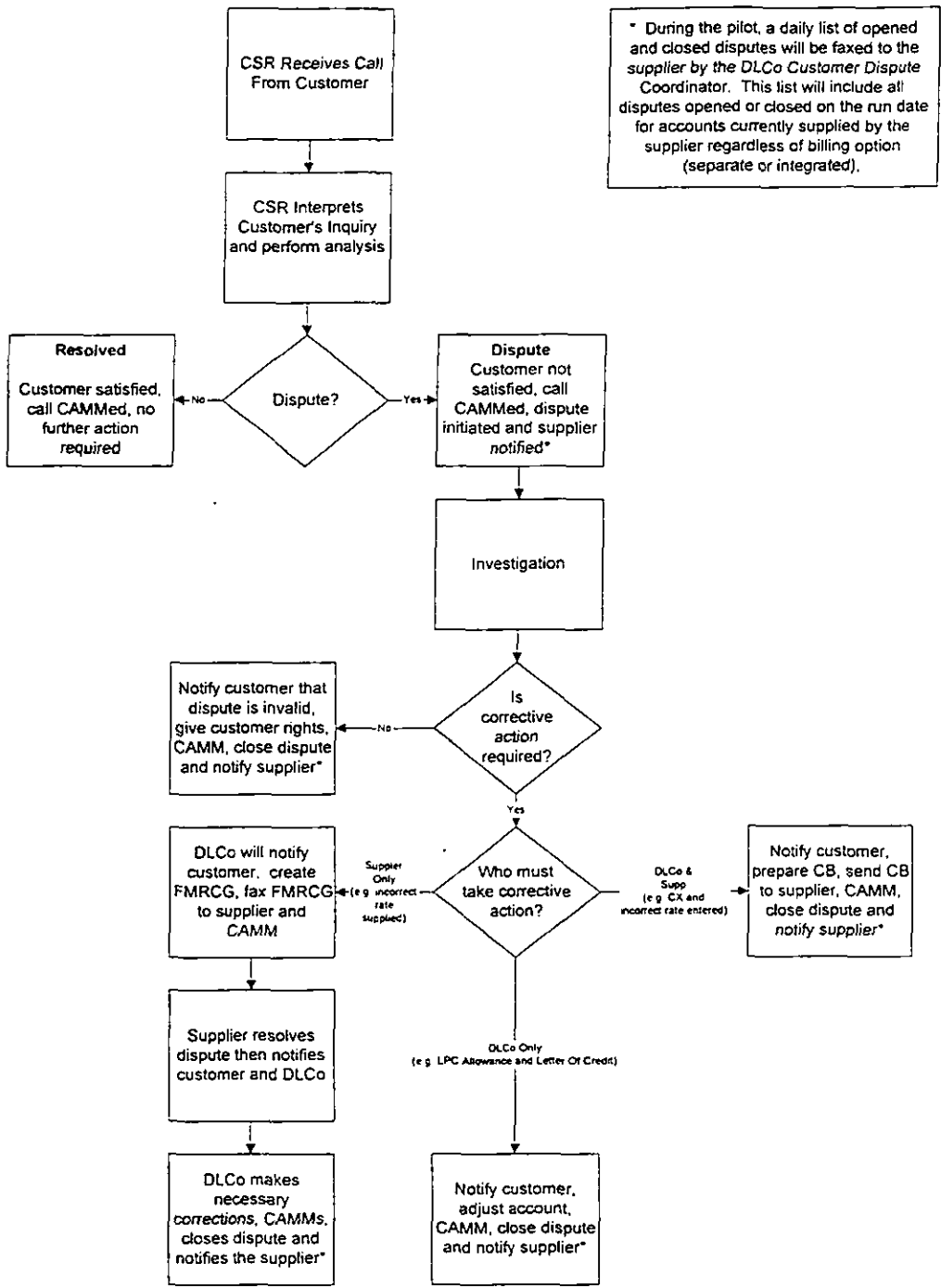
<sup>8</sup> Type - A - alphanumeric & N - numeric (all numeric types are signed numbers)

Appendix H - Payment Processing Interface -continued

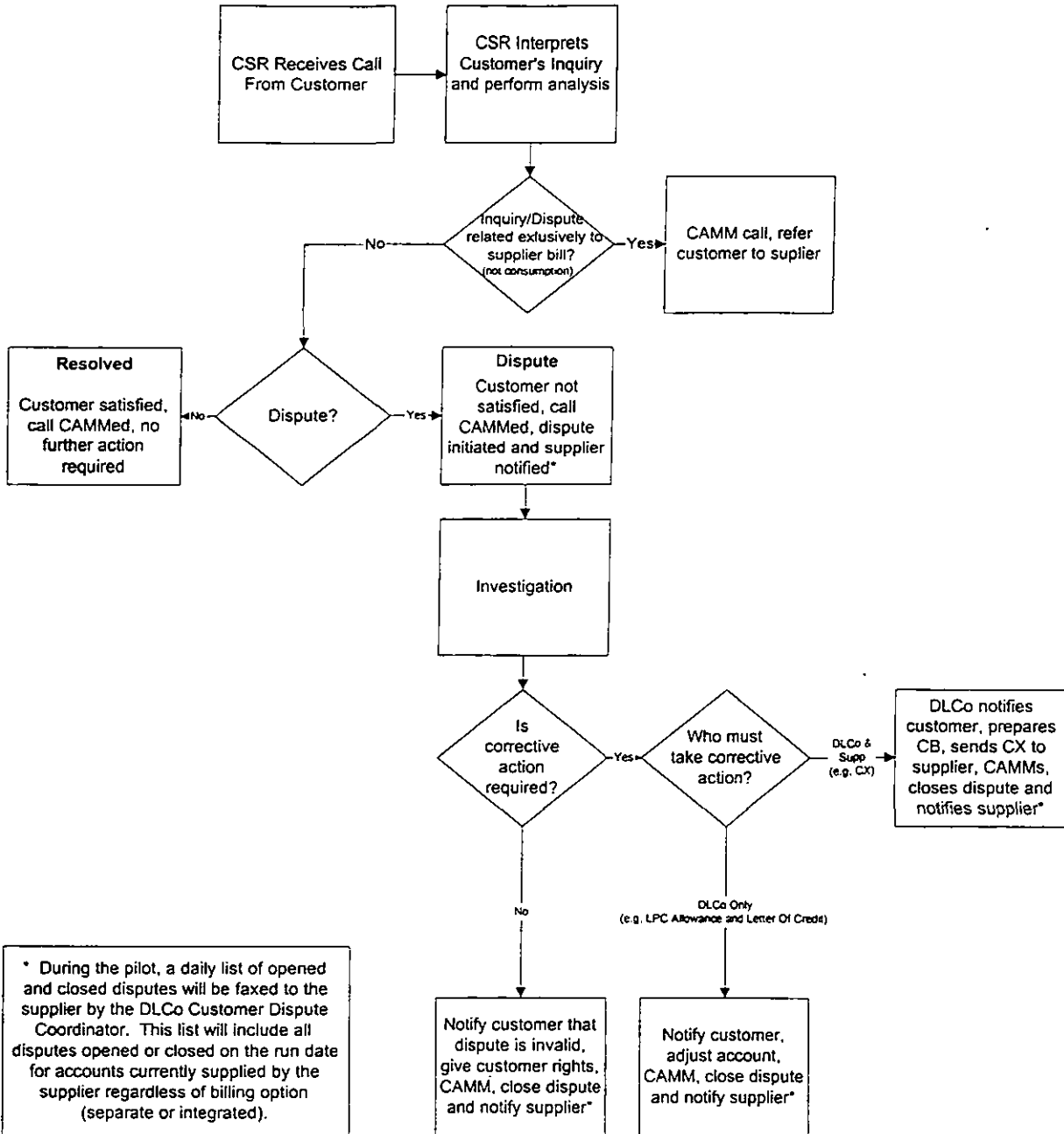
**Trailer**

	Field Name & Description	Starting Position	Length	Type	Comments
1.	<b>TLR-SUPP-ID</b> - Supplier-ID Unique identifier assigned by DLCO to a supplier.	1	10	A	
2.	<b>TLR-REC-TYPE</b>		1	A	A = Header B = Detail C = Trailer
3.	<b>TLR-PYMT-CNT</b> - Total number of payments.		7	N	
4.	<b>TLR-AR-CR-CNT</b> - Total number of A/R credits.		7	N	
5.	<b>TLR-AR-DR-CNT</b> - Total number of A/R debits.		7	N	
6.	<b>TLR-NSF-CNT</b> - Total number of NSF's.		7	N	
7.	<b>TLR-AR-ADJ-CNT</b> - Total number of A/R adjustments.		7	N	
8.	<b>TLR-PYMT-AMT</b>		12	N	Contains two assumed decimal values.
9.	<b>TLR-AR-CR-AMT</b>		12	N	Contains two assumed decimal values.
10.	<b>TLR-AR-DR-AMT</b>		12	N	Contains two assumed decimal values.
11.	<b>TLR-NSF-AMT</b>		12	N	Contains two assumed decimal values.
12.	<b>TLR-AR-ADJ-AMT</b>		12	N	Contains two assumed decimal values.
13.	<b>TLR-CURRENT-AR</b> - The sum of all of the supplier's actual account balances in DISCUS. This should balance to the sum of all the actual balances for DLCO in tegrated billing customers in the supplier's A/R system.		12	N	Contains two assumed decimal values.
14.	<b>FILLER</b>		43	A	Blanks

**I. Appendix I - Dispute Processing Flowchart (Consolidated Billing Customers)**



**J. Appendix J - Dispute Processing Flowchart (Separate Billing Customers)**



\* During the pilot, a daily list of opened and closed disputes will be faxed to the supplier by the DLCo Customer Dispute Coordinator. This list will include all disputes opened or closed on the run date for accounts currently supplied by the supplier regardless of billing option (separate or integrated).

## Acronym Definitions for Appendices H and I

<u>Acronym</u>	<u>Definition</u>
CAMM	Credit Application Memo File
CB	Corrected Bill
CSR	Customer Service Representative
CX	Consumption History
DLC	Duquesne Light Company
FMRCG	Field Memo Check for Rate Change
LPC	Late Payment Charge

***K. Appendix K - Company Holidays***

**New Year's Day**

**Good Friday**

**Memorial Day**

**Fourth of July**

**Labor Day**

**Thanksgiving Day**

**Christmas Day**

**Duquesne Statement No. 9-R**

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY  
DOCKET NO. R-00974104**

**Rebuttal Testimony  
of  
Mark G. Karl**

**Contents:**

**Response to Intervenor Testimony Regarding the Required Level of  
ECAR Planning Reserves, Modeling Issues, and Transmission  
Constraints Considered in Plant Shutdown Analysis**

## REBUTTAL TESTIMONY OF MARK G. KARL

1        **I.        Overview**

2        Q.        Please state your name and address.

3        A.        My name is Mark G. Karl. My business address is 411 Seventh Avenue, P.O.  
4                Box 1930, Pittsburgh, Pa. 15230 -1930.

5

6        Q.        Have you previously testified in this proceeding?

7        A.        Yes. I submitted direct testimony (Duquesne Statement No. 9) and various  
8                supporting exhibits (MGK-1 through MGK-7 ) with the Duquesne Light  
9                Company August 1, 1997 restructuring filing.

10

11        Q.        What is the purpose of your rebuttal testimony?

12        A.        My testimony has three main purposes. First, I respond to intervenor testimony  
13                concerning their assumptions about the required level of planning reserves in  
14                ECAR. Second, I respond to specific modeling issues raised in the intervenor  
15                testimony. Third, I discuss the transmission constraints in the Duquesne system  
16                that must be considered in any shutdown of the Elrama plant, as advocated by a  
17                number of witnesses. In addition to these purposes, I respond to a number of  
18                miscellaneous issues raised in the intervenor testimony.

19

20        **II.        Planning Reserves in ECAR**

21        Q.        A number of intervenor witnesses have modeled or forecast market prices based  
22                on assumptions about the required or likely level of planning reserves in ECAR.  
23                Is there a specific reserve margin required in ECAR?

1 A. ECAR does not set specific reserve margins for its members, nor does it require  
2 its members to meet reserve margin criteria, such as a "one day in ten years" loss  
3 of load probability. ECAR is unlike PJM in this regard; in PJM, the member  
4 utilities are required to maintain specific reserve margins that are assigned by the  
5 pool. The planning reserves adopted by individual utilities within ECAR are  
6 therefore simply that: planning reserve margins adopted by individual utilities,  
7 not reserve margins required by ECAR. Traditionally, each utility set its reserve  
8 margin at a level consistent with prevailing regulatory policies regarding the  
9 appropriate level of reliability. The only mandatory generation reserve  
10 requirement is the 6% ECAR operating reserve (comprised of 3% spinning and  
11 3% supplemental reserve). This requirement was discussed in the direct  
12 testimony of Mr. Irvin and the pricing of the associated services was discussed in  
13 the direct testimony of Mr. Lahtinen.

14  
15 Q. How have the intervenors modeled the reserve margin requirements?

16 A. Mr. Smith for the OCA (p.4) models an 8% reserve margin as appropriate for  
17 market projections. To do so he models the value of capacity as an adder to the  
18 energy price based on the levelized carrying cost of a new combustion turbine.  
19 Mr. Falkenberg adopts the same approach and uses 15%. Mr. Russel of MAPSA  
20 does not explicitly model the effect of a reserve margin requirement but asserts  
21 that a 12% reserve margin will be required.

22  
23 The 12% to 15% reserves referenced by Mr. Russell and Mr. Falkenberg are  
24 planning reserves which would typically be used by a regulated utility in the  
25 development of a Resource Plan. As indicated, however, these reserve margins,

1 as it relates to ECAR, are not based on regional requirements. It is inappropriate  
2 for these witnesses to assume that any particular level of reserves will be required  
3 by ECAR in the future; it may be that ECAR permits the market to determine the  
4 level of reserves that it is willing to pay for (with the exception, as indicated, of  
5 the 6% daily operating reserves).

6  
7 Duquesne's position with regard to reserves is similar to that of ENRON as  
8 described in the testimony of Mr. Lynn Coles (pp.15-21). Competitors should  
9 only be expected to provide spinning reserves, and the deregulated marketplace  
10 should be allowed to set the planning reserve level. It is inappropriate to force all  
11 suppliers to meet a 'one size fits all' reserve level, and it is incorrect to assume a  
12 planning reserve level in the development of market prices where no such reserve  
13 level is required by the region.

14  
15 **III. Modeling Issues and Limitations of Forecasting**

16 Q. Duquesne has argued in its direct case for a market-based approach. What  
17 concerns do you have about the forecast approach adopted by the opposing  
18 intervenor witnesses?

19 A. Mr. Schnitzer's direct and rebuttal testimony addresses the inherent limitations on  
20 forecasting avoided costs and market prices. Mr. Schnitzer describes at length the  
21 inability of forecasters to predict, with reasonable accuracy, future energy prices,  
22 given the inability to predict changes in technology and other factors that material  
23 effect those prices. I agree with those conclusions. My focus in this section is on  
24 a related, but conceptually distinct, issue. To explain, it is necessary to  
25 understand that Mr. Schnitzer's conclusions are valid whether or not he believes

1 forecasters are using the best data available (or even whether the best data  
2 available has substantial flaws). His point is that no one can accurately predict,  
3 using any data source, events 10 to 30 years into the future. My testimony  
4 focuses, instead, on the inherent flaws or limitations in many of the data sources  
5 available today, and particularly those that are utilized by the OCA and DII.  
6 Given the limitations in these data sources, I conclude that, even if one were to  
7 desire a long-range forecast of electricity prices, the data sources relied upon by  
8 these parties have substantial limitations, thereby severely limiting their utility in  
9 forecasting electricity prices.

10  
11 Q. Both Mr. Smith for the OCA (p. 15) and Mr. Falkenberg for the Duquesne  
12 Industrial Intervenors (p. 41) state they obtain unit availability data from the  
13 NERC GADS database. Are there limitations on the usefulness of this data?

14 A. Yes. The problem with using this source is that the data for specific generating  
15 facilities is not available from NERC, since the data is provided under a  
16 *confidentiality provision that states individual plant data will not be made*  
17 *available without the written permission of the owner.* As a result, the GADS  
18 data is available only for groupings of 'similar' plants. The problem with this  
19 situation is that it is nearly impossible to find plants/ units sufficiently similar to a  
20 plant such as Elrama to accurately model its availability.

21  
22 Q. In the testimony of Mr. Smith for the OCA (p. 16) he uses a 75% annual  
23 availability for both the Beaver Valley and Perry nuclear facilities. Mr. Kahal for  
24 the OCA (p. 43) cites the low availability of these units as both a rationale for

1 closure, and as a potential area for improvement. Are these claims regarding  
2 Duquesne's nuclear units valid?

3 A. No. The nuclear operations units of both Duquesne and Centerior are engaged in  
4 programs to improve the financial and operational performance of these units.  
5 Mr. Duckworth has testified to the projections associated with both the Perry  
6 Course of Action and with the Excellence 2000 program at Beaver Valley. It is  
7 particularly interesting, given the amount of testimony criticizing Duquesne for  
8 supposedly neglecting to take performance improvements into account, that in this  
9 instance Mr. Kahal has chosen to arbitrarily reduce Duquesne's nuclear  
10 availability projection to bolster his shutdown argument. In this analysis,  
11 Duquesne has built high nuclear availability numbers into its case, and should  
12 these units fail to meet these availabilities, the impact will be borne by  
13 Duquesne's shareholders through the minimum amortization commitment.

14

15 Q. Mr. Falkenberg for DII (p. 35) states that his probabilistic model requires the  
16 creation of a load duration curve. Does your analysis include such a curve and if  
17 so what was the source of your data?

18 A. A load duration curve typically refers to the distribution of loads throughout the  
19 year. Such a curve is a graph which depicts the number of hours in a year that  
20 system load is expected to equal a given megawatt level. With a load duration  
21 curve, the actual hourly, daily, and weekly variation in load is obscured, since  
22 duration curves are typically developed on an annual basis. If a load duration  
23 curve were to be used as input to a production cost simulation, the cost analysis  
24 could only be conducted on an annual basis. In a traditional production cost

1 simulation, a load duration model would produce results that would benchmark  
2 reasonably well to more detailed models such as PROMOD.

3  
4 While this analysis would produce reasonably accurate annual cost data, it would  
5 not accurately predict the revenue derived from a competitive market. In  
6 competition, it is assumed all operating generators would be compensated at the  
7 hourly market price. Since there is considerable variation in the hourly price, it is  
8 essential that an hourly model be used to capture the revenue each generator will  
9 derive from the market. An annual model will not capture the actual variation of  
10 on and off peak revenue both above and below the production cost line. This  
11 simply comes down to the difference between a cost based versus a market based  
12 analysis.

13  
14 The PROMOD analysis presented in testimony uses Duquesne's actual 1996 load  
15 shape. The model converts the actual hourly load data into a percentage of peak,  
16 and this shape is multiplied by Duquesne's peak load forecast to develop  
17 projected hourly loads. Duquesne's analysis therefore uses a projection of actual  
18 hourly loads derived from the 1996 load shape, not a load duration curve.

19  
20 Q. Why did Duquesne choose to utilize the actual 1996 load shape for this load  
21 projection?

22 A. The competition statute required all data used in the calculation of stranded costs  
23 to be obtained from 'known and measurable' sources, and directed that the most  
24 current available data be used. Duquesne had considered various means of  
25 deriving ECAR load and price shapes, but any such derivation would fail the

1 'known and measurable' test. It was therefore decided to utilize the 1996 actual  
2 hourly loads to derive the load shape, and to utilize the 1996 system lambda to  
3 derive the market price shape. As addressed in my previous testimony, the hourly  
4 lambda only set the price shape; the actual hourly prices were derived from  
5 Duquesne's forward sale.

6  
7 Q. Mr. Smith for the OCA (p. 15) uses an average of the 1995/ 1996 combined  
8 Allegheny and Duquesne load shapes in his analysis. How does that shape  
9 compare with the shape used by Duquesne?

10 A. Allegheny and Duquesne have very different load shapes. Allegheny has winter  
11 peaking load while Duquesne has summer peaking load. Development of a  
12 combined load shape requires an assessment of the individual customer classes of  
13 each company, and the loads of each customer class should be aggregated together  
14 to ensure that class load diversity is considered in the load projection.

15  
16 Simply averaging two years together could also create a distorted shape. Since  
17 load is strongly correlated with weather, the normal procedure is to adjust the  
18 hourly loads for actual observed weather conditions. Most forecasters use an  
19 algorithm which adjusts load up or down as a function of the number of degree-  
20 days above or below normal. If loads were averaged over a number of years, the  
21 result of the average should converge with the degree-day calculation, but a two  
22 year average would not.

23  
24 In addition, using the 1995 load shape in the development of a production cost  
25 based market price projection would upwardly bias the market price projection.

1 1995 was an all-time record load year for Duquesne and likely for many other  
2 midwestern utilities. Since that year had many days with well above normal  
3 temperatures, and as a result above normal loads, using that load shape would  
4 over-utilize many intermediate and peaking load facilities. If that load shape is  
5 'locked into' the analysis and projected forward, the resulting analysis would  
6 predict higher than average load requirements and market prices. It appears that  
7 Mr. Falkenberg for the DII may have 'locked in' the 1995 load shape, while it is  
8 clear that Mr. Smith for the OCA 'locked in' his 1995/ 1996 average shape.  
9

10 Q. Are there any other issues which must be considered regarding the choice of load  
11 shape for this analysis?

12 A. Yes. The discussion in the above response regarding the issues of load diversity  
13 and the need to address customer class load shapes was directed to the analysis of  
14 the combined Duquesne/ Allegheny system by Mr. Smith. These issues are  
15 significantly more important in the analysis of all of ECAR conducted by Mr.  
16 Falkenberg. Although Mr. Falkenberg obtained his load data from ECAR, and  
17 ECAR does attempt to correct for the effects of load diversity in its forecast, no  
18 single unified load forecast for the ECAR region exists. The ECAR forecast is an  
19 aggregation of all the individual company submissions.  
20

21 Another significant caveat exists regarding the load shape used in this analysis. It  
22 is normal practice to use a single shape for the duration of a production cost study.  
23 Strictly speaking, this is incorrect, since different customer classes grow at  
24 different rates, and since each class has its own load characteristics, the overall  
25 load shape changes over time. Under traditional utility regulation this effect is not

1 a large problem, but as the market deregulates it is likely that different customer  
2 classes will respond to retail choice in vastly different ways. The result is that  
3 system load shapes are likely to change dramatically as customers respond to  
4 opportunities in the marketplace. These changes are impossible to predict. By  
5 using a static load shape to predict future market prices, the analysis fails to  
6 capture the true nature of the deregulated market.

7  
8 Q. Is it correct that other important inputs into a production cost analysis are the heat  
9 rate and the operating characteristics of the generating plants in the study.

10 A. Yes.

11  
12 Q. Are the heat rates used in the production cost analyses of Mr. Smith and Mr.  
13 Falkenberg reasonable?

14 A. Mr. Smith uses the as-operated heat rates which he obtains from FERC Form 1.  
15 He argues that this data reflects real world operating factors, and is the best  
16 indication of the performance which can actually be expected from the unit.  
17 While this argument has some merit, the problem with as-operated heat rates is  
18 that they are only accurate for levels of output near those in the year the data was  
19 reported. If the production cost model operates the unit differently than in the  
20 data year, the predicted fuel cost could differ substantially from the cost which  
21 really would be observed at that level of output.

22  
23 Mr. Falkenberg uses the EIA Form 860 for full load heat rates as his heat rate  
24 input data. While the full load heat rate is a better choice for this analysis, once  
25 again, use of a single heat rate throughout the output range is incorrect, as is the

1 implicit assumption that output is continuously variable over the output range.  
2 While this assumption would result in lower cost operation for the regional  
3 dispatch, thereby moving results toward a lower market price, it also neglects the  
4 impact of unit must run status, minimum load blocks, and discrete versus  
5 continuously variable output increments.  
6

7 Q. Fuel prices are another major input to a production cost study. Are the fuel prices  
8 used by the intervenor witnesses reasonable?

9 A. Mr. Smith obtains base year fuel data from the testimony of this witness and from  
10 testimony filed in the West Penn restructuring case, supplemented by FERC data.  
11 These data sources were utilized since Mr. Smith only modeled the joint  
12 Duquesne/ Allegheny system. Mr. Falkenberg obtained his base fuel data for the  
13 ECAR region from FERC Form 423 and Form 1. Both of these are reasonable  
14 sources of data for these analyses; however as with heat rate data, this fuel data is  
15 only accurate for levels of output close to the base data year.  
16

17 Most fuel contracts contain both fixed and variable price components, and the fuel  
18 supply portfolio for an individual plant is likely to contain a mix of contracts  
19 involving different volumes and price points. If calculated plant outputs deviate  
20 significantly from base year levels, the calculated fuel cost is likely to differ from  
21 the cost which actually would be observed at that level of output. This is another  
22 example of the problems with the use of production cost analyses to determine a  
23 market price.  
24

1 For fuel escalation, Mr. Smith uses escalation rates obtained from DRI's spring  
2 1997 forecast, while Mr. Falkenberg uses the 1997 EIA Annual Energy Outlook.  
3 Either of these forecasts are reasonable sources of escalation data for coal or  
4 nuclear fuel. The difficulty with these forecasts lies in their natural gas price  
5 projections. Although Duquesne's gas price forecasts are more thoroughly  
6 addressed in the testimony of Mr. Schnitzer, Duquesne has found that the gas  
7 forecasts have consistently predicted market prices and escalation rates  
8 substantially in excess of the actual market price. Essentially, over the years, the  
9 forecasts have anticipated a surge in market prices when 'the gas bubble bursts'.  
10 This price surge has consistently been three to five years after the forecast date,  
11 and each time the forecast is updated the surge date is delayed. In reality the  
12 bubble hasn't burst, and over the past eight years the forward market has more  
13 accurately predicted market prices.

14  
15 Q. Regarding gas prices, Mr. Weisenmiller for Hospital Shared Services (p. 128)  
16 points out a discrepancy between the gas prices used in Duquesne's Integrated  
17 Resource Plan and the prices used by Mr. Schnitzer. Please explain this  
18 discrepancy.

19 A. At present, the only use of natural gas on the Duquesne system is as light off fuel  
20 and flame stabilization at the Cheswick and Elrama plants. Cheswick is also  
21 equipped for gas co-firing which will be used to help this plant meet NOx  
22 standards. Since these are relatively low volume and intermittent uses, it is  
23 difficult to obtain the type of favorable contract which could be expected for fully  
24 gas fired plant. The other use of gas in the Integrated Resource Plan was as a fuel  
25 source for proxy 'future combustion turbines.' Without good contract data to rely

1           upon, Duquesne has historically obtained gas price forecasts from organizations  
2           such as DRI and WEFA for use in the Integrated Resource Plan.

3  
4           However, Duquesne believes that use of market price evidence for gas contracts  
5           as provided by Mr. Schnitzer is preferable to the use of public gas price forecast  
6           data as part of a stranded cost analysis. This is consistent with Duquesne's  
7           proposals for a market-based approach to determining stranded costs in this  
8           proceeding.

9  
10          Q.     Operating and maintenance cost projections for Duquesne's facilities are  
11                addressed by Mr. Smith and Mr. Kahal for the OCA and by Mr. Weisenmiller for  
12                Hospital Shared Services. Duquesne's projections are compared to benchmark  
13                data and O&M cost reduction targets are proposed. Please comment on these  
14                targets.

15          A.     Mr. Smith (p. 15) states that he obtained variable O&M costs from assumptions  
16                provided by Philadelphia Electric in their restructuring proceeding. Mr. Kahal  
17                (pp. 20-21) states he feels it is reasonable to factor some productivity  
18                improvement into the O&M forecast, then later in his testimony assumes a 40%  
19                reduction in non-fuel O&M. Dr. Weisenmiller (p. 17) proposes that Duquesne  
20                factor in reductions to bring the company up to 'best practices', then later (p. 62-  
21                64) benchmarks Duquesne's costs to the rest of ECAR.

22  
23                The key to performing meaningful benchmarking is the development of relevant  
24                performance measures and the selection of a relevant comparison panel. Within  
25                Duquesne's own system, a comparison of Elrama O&M costs to those of

1 Mansfield 1 is irrelevant, even though both are scrubbed coal units located in  
2 Southwest Pennsylvania. Elrama is a four unit plant at 470 MW, while Mansfield  
3 1 is one of three 800 MW units. Elrama will never achieve the level of O&M  
4 performance that could be expected of Mansfield. In determining the potential for  
5 cost reduction at Elrama, this facility must be compared to comparable units.

6  
7 With regard to the potential for cost reductions, Mr. Duckworth has provided  
8 testimony concerning the 'Perry Course of Action', and the Beaver Valley  
9 'Excellence 2000' program. Mr. Nelson has testified to Duquesne's fossil 'Vision  
10 2000' program. The benefits associated with these programs are already built into  
11 this analysis.

12  
13 Q. Dr. Weisenmiller (pp. 129-132) has questioned the difference between the  
14 inflation forecast provided in your prior testimony and the inflation used by Mr.  
15 Clayton and Mr. Schnitzer. He also has questioned the validity of the forecast.  
16 Please explain the discrepancy between the Duquesne witnesses and explain why  
17 Duquesne considers the forecast to be valid.

18 A. Duquesne obtained the forecast of inflation from Wharton Econometric  
19 Forecasting Associates (WEFA), a commonly used and reputable econometric  
20 forecasting service. The forecast is the Gross National Product Implicit Price  
21 Deflator (GNPIP), and the forecast was given to intervenors in discovery. This  
22 forecast was provided to Mr. Clayton, who simply rounded the yearly fluctuations  
23 to a single inflation rate of 2.5%. Mr. Schnitzer used the same inflation rate used  
24 in Mr. Clayton's analysis. In the PROMOD production cost model, the analyst  
25 used the escalation stream directly from WEFA. The impact on final results

1                   between an escalation stream which moves between 2.4% and 2.7% versus a 2.5%  
2                   flat rate is unlikely to be material.  
3  
4           Q.       The final major input to the cost-based market analyses is the capital cost  
5                   associated with new capacity. Mr. Weisenmiller (p. 123) has pointed out a  
6                   discrepancy between the assumed cost of new capacity in Duquesne's Resource  
7                   Plan, and the costs in the testimony of Mr. Schnitzer. Please explain this  
8                   discrepancy.  
9           A.       This discrepancy is similar to that discussed above regarding gas price forecasts.  
10                   The new combustion turbine units included in Duquesne's Resource Plan were  
11                   not actually intended to be constructed. The Resource Plan clearly stated that  
12                   these units were simply proxies for future competitive solicitations. As such, they  
13                   were intended to represent an upper boundary price. There was not a detailed  
14                   construction estimate prepared for these facilities as part of the Integrated  
15                   Resource Planning process. Duquesne believes that the range of costs presented  
16                   by Mr. Schnitzer represents an appropriate cost estimate for new capacity.  
17  
18           Q.       Mr. Falkenberg (p. 16) states that a production cost analysis to forecast market  
19                   prices requires a forecast of capacity additions in a competitive market. He  
20                   obtains this forecast from the ECAR OE-411. Is this an accurate projection of  
21                   capacity additions in the competitive market.  
22           A.       Review of the OE-411 seems to indicate that utilities have a tendency to report  
23                   future units to meet some internally preferred reserve margin target, and that these  
24                   targets are not consistent. In addition, a single market would likely build fewer  
25                   units to meet regional reliability criteria, instead of a reserve target, because of

1 diversity benefits. This reserve margin issue has already been discussed in this  
2 testimony.

3  
4 The real problem with using the OE-411 data is that this data represents the  
5 regulated status quo, not the competitive market. The data reported in the OE-411  
6 is prepared by regulated utilities with an obligation to serve, and the data is  
7 typically drawn from each utilities Integrated Resource Plan. The units proposed  
8 for addition are regulated units, with a cost-of-service guarantee. In a competitive  
9 marketplace generation suppliers might build entirely different units. They may  
10 offer enhanced incentives for customers to accept interruptible service, and  
11 customers may freely choose different reliability and therefore different reserve  
12 levels. The OE-411 data will be largely irrelevant in a competitive generation  
13 market.

14

15 Q. With regard to the valuation of existing assets, Dr. Weisenmiller (pp. 101-102)  
16 discusses the value of the Brunot Island facility. On those pages he claims that  
17 Duquesne plans to exploit the value of Brunot Island by building new capacity on  
18 this site. Is this true?

19 A. No, this statement is not true and has been constructed by taking a number of  
20 issues out of context. Dr. Weisenmiller, at p.102:2-6 states "According to the  
21 Company's IRP filed in September, 1997, Duquesne expects to restore to  
22 commercial operation Brunot CT units, 'to support.....long-term off system  
23 sales,' presumably at deregulated rates, after the year 2000, and to reactivate a CC  
24 facility in 2007, after the transition period contemplated by the Act."

25

1 I will address each of these issues in turn. Duquesne's annual resource plan was  
2 filed with the Pennsylvania Utility Commission in May of 1997, not in September  
3 of 1997. Regarding the 1997 IRP, the PaPUC, Office of CEEP issued a letter  
4 stating that for 1997, since Pennsylvania utilities were filing restructuring plans  
5 that would address many of the issues contained in the IRP, it would be  
6 acceptable to simply update the 1996 plan to include 1996 actual operational data.  
7 A complete plan did not have to be developed separate from the restructuring  
8 filing, and no such plan was developed.

9  
10 In the case of Duquesne, the May 1997 filing consisted of a copy of the 1996 plan  
11 with a set of updated data tables from the appendix of that report. None of that  
12 data was optimized for changes in the market which occurred since that plan was  
13 filed in May 1996, which would include the change from an obligation-to-serve  
14 market to a competitive market. A copy of the letter from CEEP was provided to  
15 HSS in response to interrogatories.

16  
17 Dr. Weisenmiller seems also to imply that Duquesne is secretly planning to  
18 reactivate Brunot Island after the transition to competition is complete, to capture  
19 deregulated sales revenue to the sole benefit of shareholders. As evidence he  
20 includes the quote "to support.....long-term off-system sales". It was difficult to  
21 locate this quote in the resource plan, but it turned up as a footnote to table IRP-  
22 ELEC-3A. The full quote reads "Duquesne expects the Brunot Island Simple  
23 Cycle Combustion Turbines to be restored to commercial operation in 2001, 2003,  
24 and 2005 to support retail load growth and long term off-system sales." The  
25 portion of the quote Dr. Weisenmiller apparently forgot to include in testimony,

1 refers to a reactivation "to support retail load growth" which should be a clear  
2 indication that this plan was developed for a regulated, not a deregulated market.

3  
4 Further evidence that this plan is out of date comes from the reference to planned  
5 reactivation of the simple cycle turbines in 2001, 2003, and 2005. However,  
6 Brunot Units 2A and 2B were actually reactivated in the summer of 1996, as part  
7 of the Fort Martin sale agreement. To determine what Duquesne's plans actually  
8 were, and are, regarding Brunot Island and other future capacity, perhaps it would  
9 be useful to review the entire plan rather than just the Appendix.

10  
11 As stated above, the plan referenced in Dr. Weisenmillers' testimony was  
12 optimized for a 1996 regulated market, not a 1997 deregulated market. Still, it is  
13 instructive to review this document to reveal Duquesne's thinking with regard to  
14 new generating capacity *prior* to the passage of deregulation legislation in  
15 Pennsylvania. The following paragraphs are extracted directly from Duquesne's  
16 1996 IRP, Section 10 - Evaluation and Integration of Resources, under the  
17 heading "Preferred Supply Side Plan", with emphasis added.

18  
19 Duquesne's Brunot Island Combined Cycle (BICC) facility is expected to be utilized to  
20 provide peaking and intermediate service capacity for Duquesne's retail customers and  
21 will also serve as back-up capacity for long-term firm bulk power sales. The combined  
22 summer rating of the BICC combustion turbines and steam turbine will be 267 MW. For  
23 current planning purposes the BICC facility is assumed to return to service in stages  
24 beginning in the summer of 1997. Two of the three combustion turbines, each rated 45 MW  
25 summer capacity and 56 MW winter capacity, are expected to be returned to service in 1997.  
26 The remaining combustion turbine and the steam turbine generator are expected to be  
27 returned to service in 2001. The anticipated reactivation of BICC assumes that each  
28 component meets a least-cost resource test. However, depending on the actual rate of  
29 growth in peak demand, the success of DSM programs and the level and timing of the

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implementation of long-term firm bulk power sales, the reactivation schedule for BICC can be advanced or delayed with minimal impact on the least-cost resource plan.

In the long term, in order to continue to move in the direction of an optimized capacity mix, any additional future capacity acquisitions and/or projects are expected to be limited to peaking resources. A gas turbine peaking facility having a summer capacity rating of 140 MW has been established as representative of the Company's preferred supply-side resource for the purpose of establishing the Company's avoided capacity cost. The identification of this peaking facility is presented for planning purposes only and should not be assumed to be a commitment by the Company to pursue this resource at the exclusion of other alternatives.

Duquesne intends to aggressively pursue additional DSM programs which meet market-based avoided cost tests. In addition, the avoided cost of the gas turbine peaking facility establishes a cost cap for the acquisition of non-utility generation and bulk purchases of energy and/or peaking capacity from other utilities, marketers or other potential suppliers. Based on this cost cap, Duquesne intends to pursue all least-cost opportunities to acquire peaking resources, such as firm purchases from other utilities, diversity exchange agreements with other utilities, non-utility generation facilities and/or competitive procurement solicitations, in order to defer or eliminate the need for the construction by Duquesne of any power generation facilities.

The timing of the addition of peaking resources will be affected by the actual experience in load growth, the actual results of the Company's DSM programs, the Company's ability to purchase power from other utilities and the availability of new cost-effective cogeneration and renewable resource generation. Based on the use of a gas turbine having a summer rating of 140 MW as a proxy unit to represent the addition of peaking resources, the 1995 preferred resource plan includes the addition of peaking resources in the years 2009 and 2015. As discussed earlier, the Company intends to vigorously pursue all least-cost opportunities which will defer or eliminate the need for the addition of peaking facilities.

To forestall any attempt to portray the “long-term firm off-system sales” described in the passages above as deregulated sales, these sales were contemplated as taking the same form as the GPU-Phillips reactivation project,

1 which Dr. Weisenmiller references on p. 103 of his testimony. That sale was  
2 structured such that Duquesne would earn return on and of new capital,  
3 depreciation of embedded capital, and sale profits were to be returned to  
4 ratepayers.

5  
6 As stated previously, this IRP was developed in 1996, prior to passage of the  
7 retail choice legislation. That plan has, of course been superseded by Duquesne's  
8 current restructuring filing, and that filing clearly shows the remaining cold  
9 reserved units at Brunot Island as stranded. At this time, Duquesne has no plan to  
10 build, reactivate, construct, cause to be constructed, or otherwise plan to add  
11 generating capacity at Phillips, Brunot Island, or anywhere on the Duquesne  
12 system.

13  
14 **IV. Elrama Transmission Issues**

15 Q. A number of intervenors have questioned the economic viability of Elrama and  
16 other Duquesne generating units. Please describe the impacts on Duquesne's  
17 transmission system which would arise from a permanent shutdown of the Elrama  
18 facility.

19 A. As Mr. Clayton's rebuttal testimony demonstrates, when the proposed shutdowns  
20 are subjected to a proper avoidable cost analysis, only the Elrama unit is still  
21 subject to questions of economic viability. The preliminary shutdown analysis set  
22 out in Mr. Clayton's Exhibit DJC-13 evaluated Elrama as a generating unit only.  
23 Assuming a shutdown of Elrama would raise serious issues for Duquesne's  
24 transmission system.

25

1 Q. Have you looked at these issues?  
2 A. Yes. This Elrama shutdown issue has been reviewed with Duquesne's  
3 transmission planning group. The Elrama station provides both reactive and real  
4 power to support the southeast side of Duquesne's transmission system. The  
5 Elrama-Mitchell transmission tie line is one of Duquesne's primary  
6 interconnections with the Allegheny Power system, and during peak periods,  
7 Elrama also provides significant support to the Allegheny system in that area.  
8 The Elrama station serves as a first contingency in Duquesne's transmission  
9 planning. Assuming no other system faults occur, at peak, the system should  
10 remain stable without Elrama. However, any other transmission or generation  
11 fault could result in an inability to serve customers.

12  
13 Q. Has Duquesne done any load flow modeling of the impact of the loss Elrama?  
14 A. Yes. Preliminary load flow studies have been done to simulate the loss of Elrama.  
15 The transmission upgrade to fully replace Elrama would require extension of a  
16 345kV line from the Collier Substation to the Elrama Substation. Without  
17 extension of the 345kV system, Elrama could be replaced with 200 Mvar of  
18 capacitors for reactive support and 100 MW of generation to supply real power.  
19 In addition to capacitors and generation, the Elrama-Mitchell tie would have to be  
20 opened on peak to back off flows from Duquesne to Allegheny. This would  
21 increase operating costs on the APS system.

22  
23 Q. Please describe the transmission line extension required to replace Elrama.

24 A. To replace the Elrama station without any additional generation resources, a new  
25 345 kV line would be required from the existing Collier substation to Elrama.

1           The most direct route for this line would run through Upper Saint Clair and  
2           Mount Lebanon, but due to property values and anticipated fierce political  
3           resistance, this route is infeasible. The most likely routing for this line would  
4           follow the rivers, and in a best case scenario, railroad rights-of-way could be  
5           procured for this purpose. This line extension would require significant  
6           modification of the Elrama substation, with the addition of transformers and  
7           controls. Starting from scratch, the lead time for this project would be at least 4  
8           or 5 years, and Elrama could not be closed until the line is completed. Any right-  
9           of way problems would add significantly to the lead time and cost of the project.

10  
11        Q.     Are there other options to deal with these Elrama transmission issues?

12        A.     Yes. By installing 200 Mvar of capacitors on the system, the reactive power  
13           problem can be alleviated. The system would still need at least 100 MW of  
14           generation at the substation site, and there are at least three potential options for  
15           addressing this need. The first option would be to allow Elrama Unit 4 to remain  
16           in operation, while closing Units 1, 2, and 3. The second option would be to  
17           relocate the Brunot Island units 2A and 2B to the Elrama substation. These units  
18           are rated 56 MW (ISO), and together would provide 112 MW of generation. No  
19           environmental or other permitting issues associated with this move have yet been  
20           addressed. The final option would require installation of a new 100 MW turbine  
21           at this site. No permitting issues associated with installation of a new emission  
22           source have yet been addressed.

23  
24        Q.     Has the company reached a final decision regarding the shutdown of Elrama?

1 A. No. As discussed in Mr. Marshall's testimony, Duquesne has committed to file a  
2 detailed shutdown analysis with the Commission by the end of 1998.

3

4 **V. Miscellaneous Intervenor Issues**

5 Q. In the testimony of Mr. Schoengold (pp. 4-9) for ENV, he argues that all existing  
6 generating facilities in Pennsylvania should be required to meet environmental  
7 new source performance standards, and that all out of state generation selling to  
8 Pennsylvania should also meet these standards. What would be the impact of  
9 such a requirement?

10 A. The imposition of such a requirement would force Pennsylvania utilities to invest  
11 hundreds of millions of dollars in environmental controls that would reduce the  
12 operational efficiency of generation facilities, and dramatically increase the cost  
13 of generation in the state. Many otherwise viable older generating units in  
14 Pennsylvania would be incapable of meeting new source standards. These units  
15 would have to be shut down and replaced with new capacity at significantly  
16 higher cost. Out of state generation would not mitigate the cost increases, since  
17 no out-of-state generator would invest the enormous sums necessary to sell to  
18 Pennsylvania. The result would be that Pennsylvania would become isolated  
19 from the competitive marketplace. Implementation of this requirement is ill-  
20 advised.

21

22 Q. Mr. Schoengold (pp. 4-9) also requests that utilities be required to offer incentives  
23 for renewable generation resources. Is this a reasonable requirement?

24 A. No. If this generation makes economic sense it will be built. If there is a  
25 premium market available for renewable generation from customers willing to pay

1 for this generation, it will be built. An opportunity now exists for the free market  
2 to decide if customers actually are willing to pay more for “clean” power. The  
3 market should decide what level of environmental control in excess of existing  
4 federal clean air standards customers are willing to purchase.

5

6 Q. On pp. 16-18 Mr. Schoengold states that Duquesne should in the future use  
7 “targeted area planning”. Please respond to that request.

8 A. The Integrated Resource and Transmission Planning units within Duquesne are  
9 unfamiliar with the term “targeted area planning”. However, from reading the  
10 proposal of Mr. Schoengold, it seems that this term may be summarized as  
11 referring to a consideration of the transmission cost and constraints associated  
12 with capacity expansion, and a recognition that it may be beneficial to locate  
13 generation resources closer to load to avoid the need for construction of additional  
14 transmission resources. Duquesne refers to this process generically as a  
15 “distributed generation” analysis.

16

17 Distributed generation has not been much of an issue on the Duquesne system,  
18 since the transmission system is relatively small, and recent load growth has not  
19 required much in the way of transmission or generation expansion. Duquesne has  
20 invested in small pilot and demonstration programs involving distributed  
21 generation technology such as fuel cells. If the market had remained regulated,  
22 when Duquesne eventually would have considered transmission or generation  
23 expansion, these location related issues and the benefits of distributed generation  
24 would have been considered. Although the role of utility planning is unclear in a  
25 deregulated market, because the consideration of these location issues makes

1 economic as well as environmental sense, it is likely that they will still be  
2 considered in some form by whomever performs the planning function.

3

4 Q. Are there any other matters you wish to discuss?

5 A. Yes. I am sponsoring certain revised exhibits to my direct testimony. These  
6 exhibits were circulated to the parties on October 16, 1997 as part of Duquesne's  
7 corrections to its stranded cost calculations. For convenience, the entire package of  
8 revisions is included in Duquesne's rebuttal case as Ex. DJC-21, including my  
9 revised exhibits.

10

11 Q. Does this conclude your testimony?

12 A. Yes.

**Duquesne Statement No. 10-R**

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY  
DOCKET NO. R-00974104**

**Rebuttal Testimony  
of  
Ralph L. Nelson**

**Contents:**

**Response to Intervenor Testimony Regarding O&M Costs,  
Capital Costs, and Potential Cost Reductions for  
the Company's Fossil Generating Units**

## REBUTTAL TESTIMONY OF RALPH L. NELSON

1 Q. Please state your name and business address.

2 A. Ralph L. Nelson, 411 Seventh Avenue, Pittsburgh, Pennsylvania 15230-1930.

3 Q. Did you present written direct testimony in this proceeding?

4 A. Yes. I submitted direct testimony, Duquesne Statement No. 10 in the Duquesne  
5 Light Company Restructuring Plan Filing.

6 Q. What issues will you address in your rebuttal testimony?

7 A. I will address several issues which witnesses for intervenors Hospital Shared  
8 Services Administrative Resources, Inc., City of Pittsburgh, Pennsylvania, and  
9 the Office of Consumer Advocate identified in their written direct testimony.  
10 Specifically, these issues are:

- 11 • The technical issues and unavoidable costs associated with the cold  
12 reserving or permanent shut down of Cheswick or Elrama Power Station.
- 13 • The required level of NOx reductions assumed in projecting the capital  
14 and O&M costs included in my direct testimony for CAAA compliance  
15 and the potential impact of CAAA Section 110 SIP call recently proposed  
16 by the EPA.
- 17 • The potential for non-fuel O&M cost reductions at Duquesne's generating  
18 stations, resulting from competitive pressure.

1                                   **COLD RESERVE CHESWICK OR ELRAMA POWER STATION**

2           Q.     Some intervenor witnesses have presented testimony regarding the economic  
3                    desirability of cold reserving or permanently closing some of Duquesne's fossil  
4                    generating assets. With regard to the Cheswick and Elrama Power Stations,  
5                    please describe the technical issues involved in cold-reserving these facilities.

6           A.     There are several issues involved in cold reserving a facility such as Cheswick or  
7                    Elrama Power Station with the intent to return these plants to service at a later  
8                    date. The most important aspect involves the preservation of systems and  
9                    equipment to prevent or minimize degradation during the period of cold reserve.  
10                  The preservation effort includes engineering studies, analysis of every system in  
11                  the plant and the development of comprehensive plans for draining and drying  
12                  systems, establishing flow circuits for the recirculation of dehumidified air  
13                  through the systems, assuring the weather tightness of the buildings and estab-  
14                  lishment of plans and schedules for regularly rotating equipment. Caretaker  
15                  crews must be established to maintain and assure that systems remain dry and to  
16                  turn rotating equipment on a regular basis. Failure to adequately lay-up these  
17                  systems and rotate equipment regularly will result in major degradation of  
18                  systems, equipment and structures which will dramatically increase the cost of  
19                  reactivating these facilities when they are to be returned to service.

20          Q.     What is the estimated cost of placing a facility such as Cheswick or Elrama in  
21                  cold reserve?

1           A.     The cost to cold reserve a generating station is very site-specific. Duquesne's  
2                     only experience with cold reserving a multi-unit station such as Elrama is at  
3                     Phillips Power Station and based on that experience, the estimated one time cost  
4                     for laying up the Elrama station is approximately \$2,000,000. The annual cost of  
5                     direct labor and materials for continuous caretaker activities is estimated at  
6                     \$800,000 per year. The estimated one time cost for cold reserving Cheswick  
7                     Power Station, which is a single unit facility is \$1,500,000 and the annual cost of  
8                     direct labor and materials for continuous caretakers of activities is estimated at  
9                     \$500,000.

10          Q.     What is the estimated cost of reactivating Cheswick or Elrama Power Station  
11                     after three to five years in cold reserve status?

12          A.     In spite of efforts to preserve the condition of systems, equipment and structures,  
13                     some degradation will inevitably occur over time. Duquesne has no experience  
14                     with reactivation of generating units that have been cold reserved for extended  
15                     periods of time. However, Duquesne's best estimate for reactivating Elrama  
16                     Power Station after being in cold reserve for three to five years is \$51,000,000.  
17                     Duquesne's estimated cost to reactivate Cheswick after three to five years in cold  
18                     reserve is \$38,000,000. These cost estimates include the estimated cost to  
19                     rehabilitate degraded equipment and systems, restaff and train employees to  
20                     operate and maintain the facility, and to provide all of the necessary start-up  
21                     support functions. The restaffing and training expenses would be necessary

1           because most of the current employees would be either retired or in other posi-  
2           tions within the Company.

3           Q.    If Cheswick or Elrama Power Station were to be cold reserved or permanently  
4           shut down, would all of the costs associated with these plants be avoided?

5           A.    As I indicated earlier, in the event of a cold reserve situation, there would be lay-  
6           up costs and continuous caretaker costs while the plant is in cold reserve.  
7           Exclusive of these costs, most of the operating, maintenance and capital costs  
8           could be avoided. For example, we would no longer perform overhaul outages  
9           and could avoid those costs. Most, if not all O&M costs could be avoided after a  
10          short period of time and capital expenditures would be terminated immediately.  
11          Also, most future fuel costs could be avoided.

12          Q.    What fuel costs could not be avoided?

13          A.    Elrama's fuel supply includes one contract which does not expire until March 31,  
14          2000. Duquesne is obligated to take 30,000 tons per month and assuming that it  
15          could be sold at spot prices, the loss would be limited to approximately \$10 per  
16          ton. The total take-or-pay unavoidable cost would be approximately \$2,000,000.  
17          A similar contract that extends for seven years at Cheswick would result in  
18          unavoidable costs of \$6,700,000.

19          Q.    Are there any other fuel related costs that could not be avoided?

- 1 A. Yes, at Elrama Station Duquesne currently contracts for the processing of  
2 scrubber sludge for landfill disposal. There would be a one time, first year  
3 charge of \$1,000,000 for termination of this contract.
- 4 Q. With regard to operating costs, could all operation and maintenance (O&M)  
5 expenses at Cheswick and Elrama Power Stations be avoided?
- 6 A. The variable portion of the O&M expenses would be reduced to zero immedi-  
7 ately. I estimate that approximately 50% of the fixed O&M expenses could be  
8 eliminated almost immediately after cold reserving or permanently closing the  
9 plant. The other 50% would be needed to shut the plant down, lay it up for cold  
10 reserve or prepare it for permanent closure. I estimate that these activities would  
11 take 12 to 18 months. Thus, the fixed O&M would be reduced by 50% the first  
12 year, 75% the second year and 100% thereafter.
- 13 Q. What other costs at these stations could be avoided?
- 14 A. A portion of the overhead costs would be avoided in varying amounts. The  
15 details on these overhead expenses will be addressed in the rebuttal testimony of  
16 Mr. Morgan O'Brien. It is estimated that 10% of the allocated overheads would  
17 be avoided in the first year of the plant shutdown and 20% in the second year,  
18 with the company continuing to incur 80% of the corporate overhead costs  
19 thereafter.
- 20 Q. Are there any taxes that would be avoided by shutdowns of these stations?

1           A.     Yes, there are. Mr. O'Brien's rebuttal testimony will indicate that with regard to  
2                     the Pennsylvania capital stock tax, 40% of the capital stock tax allocated to a  
3                     plant would be avoided once the book value of the plant is written off. In  
4                     addition, the property taxes would be avoided when the facility is written off.  
5                     FICA taxes are avoided at the same rate as the workforce reduction.

6           Q.     Are there any other costs that would be incurred as the result of the cold reserv-  
7                     ing or permanent shut down of Cheswick or Elrama Power Station?

8           A.     *If either station were shutdown, the workforce reductions would be achieved*  
9                     *largely through layoffs and additional costs would be incurred for employee*  
10                    *severance allowances. These costs will also be addressed in the rebuttal testi-*  
11                    *mony of Mr. O'Brien.*

12          Q.     Would cold reserving or permanently shutting down either Cheswick or Elrama  
13                     Power Station create any potential operating problems on Duquesne's transmis-  
14                     sion system?

15          A.     The Cheswick and Elrama Power Stations are two Duquesne power stations that  
16                     supply real and reactive power (for voltage support) to customer loads in the  
17                     eastern portion of Duquesne's transmission system. With Cheswick or Elrama  
18                     out of service, power flows increase west to east across Duquesne's 138 KV  
19                     transmission system. The system is designed to handle such increased power  
20                     flows except that during summer peak load periods or during transmission line  
21                     outages, which occur infrequently, ampere overloads on transmission lines or low

1 voltage conditions caused by insufficient reactive power supply in certain areas  
2 can result in the necessity to interrupt or curtail customers in the affected areas.

3 Q. Can the transmission system be modified to avoid these problems if Cheswick or  
4 Elrama Power Station is shut down?

5 A. Yes, there are several alternatives for modification to the transmission system  
6 that could be implemented to avoid the potential for reliability problems with the  
7 shut down of either Cheswick or Elrama Power Station. Mr. Karl will present  
8 rebuttal testimony on these alternatives specifically as they regard a shutdown of  
9 the Elrama Power Station.

#### 10 **NO<sub>x</sub> REDUCTION ASSUMPTIONS**

11 Q. What level of NO<sub>x</sub> reductions was assumed under Title I of the CAAA in the  
12 development of the capital and O&M projections in your direct testimony?

13 A. In my direct testimony, it was assumed that under Title I of the CAAA, plants  
14 located in Pennsylvania would be required to reduce their NO<sub>x</sub> emissions by  
15 65% beginning in the year 2005. Plants located in Ohio would be required to  
16 reduce their NO<sub>x</sub> emissions by 55% beginning in 2005. The capital and O&M  
17 expenses necessary to implement the control options to achieve these assumed  
18 reduction levels were included in the cost projections. Duquesne is currently  
19 implementing the controls to achieve the 55% NO<sub>x</sub> reduction called for in the  
20 existing PA State Implementation Plan.

1 Q. Since you filed your direct testimony, has there been any events that will impact  
2 your assumptions for required NOx reductions?

3 A. Yes. The EPA recently issued a proposed CAAA Section 110 State Implementa-  
4 tion Plan (SIP) call that will increase Duquesne's NOx reduction requirements to  
5 85% as early as 2004. This would apply to plants located in Ohio as well as  
6 those in Pennsylvania and will most likely require the installation of Selective  
7 Catalytic Reduction (SCR) technology on these units in order to comply.

8 Q. Will this proposed SIP call significantly increase Duquesne's capital and O&M  
9 cost projections for the fossil units?

10 A. This proposed SIP call will significantly increase these projected expenditures.  
11 The estimated capital cost to install SCR technology and the cost to operate these  
12 systems is very site specific. However, an average cost for this technology would  
13 be \$80 per installed kilowatt. The table shown below indicates the estimate  
14 capital requirements as well as the estimated annual O&M cost for each of  
15 Duquesne's fossil generating plants.

<u>PLANT</u>	<u>CAPITAL</u>	<u>O&amp;M</u>
	<u>\$x1000</u>	<u>\$x1000</u>
19 Cheswick	45,600	4,300
20 Elrama	67,200	2,900
21 Eastlake	14,880	1,048
22 Sammis	14,960	1,054
23 Mansfield	30,000	1,542

1 The data in the table represents the estimated costs to install and operate SCR technology  
2 at each plant. At this time, Duquesne has not developed a compliance strategy to comply  
3 with the NO<sub>x</sub> reductions proposed in the EPA's recent SIP call. While it is unlikely that  
4 it would be necessary to install SCR's at all of these plants, if these proposed reductions  
5 become final, it will be necessary to install this technology at most of these facilities.  
6 None of these costs were included in my original or revised testimony.

### 7 **IMPACT OF COMPETITION ON O&M COSTS**

8 Q. A substantial amount of testimony has been filed by intervenor witnesses regard-  
9 ing the potential for cost reductions at Duquesne's fossil plants. For example, in  
10 Mr. Kahal's testimony, he references a U.S. Department of Energy (DOE) study  
11 in which it is assumed that the non-fuel operating costs will decline by 25 percent  
12 due to the onset of retail competition, with a "high efficiency" scenario assuming  
13 a 40 percent decline. In your opinion, are these realistic assessments of the cost  
14 reduction potential at Duquesne's fossil generating stations?

15 A. In my view, the potential to reduce non-fuel O&M costs is specific to individual  
16 plants for a number of reasons, including the type of fuel, the specific type and  
17 manufacturer of the equipment, and the age of the plant just to mention a few.  
18 The statements referenced in the DOE study are general in nature and do not  
19 necessarily apply to individual plants. As I indicated in my original testimony,  
20 Duquesne has achieved significant reductions in O&M expenses at our fossil  
21 generating stations through the early 1990's and in recent years costs have

1 increased at approximately the rate of inflation. As we move forward, costs are  
2 projected to increase at a rate slightly less than the rate of inflation, indicating  
3 that in terms of constant dollars, some productivity gains are being achieved.  
4 Duquesne has and will continue to seek ways to improve technologies and best  
5 practices as they develop. However, as the result of the aging of the fleet and  
6 anticipated degradation of the boilers due to the long term effects of mitigating  
7 nitrogen oxide emissions, there will be continuous upward pressure on O&M  
8 costs. In my opinion, these factors will, to a large degree, offset cost reductions  
9 achieved through productivity enhancements, thereby limiting the potential for  
10 future overall reductions in direct O&M expenses.

11 Q. Are there any other matters you wish to discuss?

12 A. Yes. I am sponsoring certain revised exhibits to my direct testimony. These  
13 exhibits were circulated to the parties on October 16, 1997 as part of Duquesne's  
14 corrections to its stranded cost calculations. For convenience, the entire package of  
15 revisions is included in Duquesne's rebuttal case as Ex. DJC-21, including my  
16 revised exhibits.

17 Q. Does this conclude your rebuttal testimony?

18 A. Yes, it does.

**Duquesne Statement No. 11-R**

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY  
DOCKET NO. R-00974104**

**Rebuttal Testimony  
of  
Ralph Duckworth, Jr.**

**Contents:**

**Response to Intervenor Testimony Regarding O&M Costs,  
Capital Costs and Costs Independent of Operation for  
the Company's Nuclear Generating Units**

**REBUTTAL TESTIMONY OF RALPH E. DUCKWORTH JR.**

1 Q. Please state your name and address.

2 A. My name is Ralph E. Duckworth, Jr. and my address is Duquesne Light Company  
3 ("Duquesne"), P.O. Box 4, Shippingport, PA.

4 Q. What is the purpose of your testimony?

5 A. I will provide rebuttal testimony to the direct testimony of Mr. David Hughes, Mr.  
6 Matthew I. Kahal, Mr. Christopher D. Seiple and others.

7 **REBUTTAL OF MR. HUGHES' TESTIMONY**

8 Q. Please summarize the first portion of your testimony.

9 A. I address Mr. Hughes' allegations that the fuel and non-fuel O&M expenses, as well as  
10 capital expenditures, of operating Perry have been excessive since it was placed in  
11 service. I conclude that these claims are either incorrect or fail to recognize that prior  
12 ratemaking actions of this Commission have protected ratepayers from increased  
13 operational costs. Finally, I explain that the operating and financial experience of Perry  
14 has improved significantly in recent years.

15 Q. Does Mr. Hughes offer any evidence of poor operating experience or high operating costs  
16 associated with Beaver Valley Unit 2?

17 A. No. And as my direct testimony shows, Beaver Valley Unit 2 performs very well when  
18 compared to the industry.

19 Q. Is Mr. Hughes correct in his assertion that Perry has suffered from poor operating  
20 performance?

- 1 A. Only to the limited extent that Perry's performance included a less than 50% operational  
2 availability in 1993 and 1994.
- 3 Q. What was the consequence of this performance?
- 4 A. The Company absorbed more than \$34 million of over budget expenditures, Duquesne's  
5 share of over budget expenditures at Perry for the years 1993-1996.
- 6 Q. Were these costs deferred for consideration in a future rate proceeding?
- 7 A. No. They were expensed immediately.
- 8 Q. Who paid for these costs?
- 9 A. These costs were borne by the Company's stockholders.
- 10 Q. Has Duquesne had a base rate proceeding since 1987 in which any increased costs related  
11 to the performance of Perry have been included in base rates?
- 12 A. No. Duquesne has not had a base rate proceeding since 1987.
- 13 Q. How do the Perry non-fuel O&M costs actually paid by customers, that is, the non-fuel  
14 O&M cost projections approved in the 1987 rate docket, compare to actual costs at other  
15 similar plants?
- 16 A. Perry's non-fuel O&M costs per MWH (three-year averages) as compared to the average  
17 industry non-fuel O&M costs for other boiling water reactors are described below. The  
18 column labeled *Current Approved Rate* shows the 1987 rate case test year projected  
19 O&M expenses actually collected from the ratepayers under current rates.

	Year	Perry Actual	Average BWR	Current Approved Rate
1				
2	1989-1991	\$20.79	\$21.43	\$17.07
3	1990-1992	\$17.23	\$21.36	\$17.07
4	1991-1993	\$20.49	\$22.26	\$17.07
5	1992-1994	\$28.73	\$21.93	\$17.07
6	1993-1995	\$28.70	\$19.76	\$17.07
7	1994-1996	\$22.29	\$18.87	\$17.07
8				

9 (Source: FERC Form 1 data provided by UDI/RDI)

10 The above table shows that although the actual non-fuel O&M costs at Perry have  
 11 fluctuated somewhat over the life of the Unit, Duquesne's customers continue to pay a  
 12 non-fuel O&M rate for Perry well below the industry average for other boiling water  
 13 reactor plants. The table also shows that for the three year average periods 1990-1992  
 14 and 1991-1993, the actual O&M costs at Perry were at or below the industry average.

15 Q. How do current fuel costs compare to the projected fuel costs approved in Duquesne's  
 16 1987 rate case?

17 A. In Duquesne's 1987 rate case, using a future test year ended March 31, 1988, Duquesne's  
 18 fuel expenses were projected to be \$7,661,604 based on a test year net output of 583,000  
 19 MWH. The unit fuel expense was projected to be \$13.14/MWH. Unit fuel expenses  
 20 actually experienced at Perry, expressed in both nominal and in inflation adjusted  
 21 constant 1987 values are as follows:

	Year	Nominal \$/MWH	Constant 1987 \$/MWH	Rate Case Pro- jection \$/MWH
1				
2	1988	14.54	14.04	13.14
3	1989	13.26	12.29	13.14
4	1990	12.63	11.21	13.14
5	1991	11.31	9.66	13.14
6	1992	10.33	8.59	13.14
7	1993	12.00	9.72	13.14
8	1994	12.28	9.72	13.14
9	1995	9.71	7.50	13.14
10	1996	6.90	5.20	13.14

11  
12

As shown above in nearly every year, fuel costs, on either a nominal or constant basis has trended significantly below the projection made for the 1988 test year in Duquesne's 1987 rate case. Perry has therefore actually experienced fuel costs significantly below rate case projections.

13  
14  
15  
16 Q. Have Duquesne's ratepayers benefitted from of the declining fuel costs at Perry?

17 A. Yes. Unlike the non-fuel O&M costs, which have not been reflected in rates (because  
18 Duquesne has not had a base rate proceeding in the last 10 years), fuel cost charges are  
19 reflected in rates through an annual update of the ECR. The actual unit fuel cost at Perry  
20 has declined significantly, an average of about 5.6% per year, since 1988. These savings  
21 have been passed directly to ratepayers on an annual basis.

22 Q. Did or are Duquesne's ratepayers paying for capital additions at Perry since the 1987 rate  
23 case?

1 A. No. Duquesne's rates have never been adjusted to reflect subsequent capital additions at  
2 Perry.

3 Q. Has the Commission previously addressed increased costs as a result of the 1993 and  
4 1994 outages at Perry?

5 A. Yes. The Commission disallowed the recovery of a portion of Perry replacement power  
6 costs incurred by Duquesne during 1993 and 1994. As a result of this disallowance,  
7 Duquesne's customers have benefitted from the decreases in fuel costs at Perry, without  
8 paying the increased Perry purchased power cost incurred by Duquesne as a result of the  
9 1993 and 1994 outages.

10 Q. Please explain the adjustments made by Duquesne to its ECR with respect to the periods  
11 of time when Perry was not in service.

12 A. An adjustment was made to the ECR in effect for the period April 1, 1994 through March  
13 31, 1995 to reflect the performance of Perry during the 12 month period ended December  
14 31, 1993. The ECR for this period was adjusted downward by \$777,409 to reflect the  
15 incremental cost of replacement power associated with performance of Perry below a  
16 50% net capacity factor (NCF) as required by Section 1322 of the Public Utility Code.  
17 (See In re Duquesne Light Company, Dkt. No. M-940524 (April 8, 1994).)

18 An adjustment was made in the ECR in effect for the period April 1, 1995 through March  
19 31, 1996 to reflect estimated replacement power costs for the last 70 days of Perry's 4th  
20 refueling outage, which lasted from February 5, 1994 through August 13, 1994, a total of  
21 190 days. The ECR for this period was adjusted downward by \$2,403,790 to reflect the  
22 estimated replacement power costs associated with the 70 days of the Perry 1 refueling

1           outage that extended beyond the 120 day threshold of Section 1322. (See In re Duquesne  
2           Light Company, Dkt. No. M-950662 (March 30, 1995).)

3       Q.     Were these adjustments approved by the Commission?

4       A.     Yes. Each adjustment was approved by the Commission as referenced above.

5       Q.     What has been the recent operating availability of the Perry Plant?

6       A.     Greatly improved. Operating availability at nuclear facilities is most appropriately  
7           evaluated from a long term perspective, rather than on the basis of only one or two years,  
8           because operating availability can vary significantly from year to year as the result of  
9           refueling outages and forced outages. Perry's lifetime capacity factor through June 30,  
10          1997 is 61.8%. Perry's capacity factors were 87.5%, 71.3% and 88.7% for 1995, 1996,  
11          and the first 8 months of 1997, respectively. Perry's capacity factor for the three year  
12          period ended December 31, 1996 was 67.2%, which is not far from the industry average  
13          of 74.3%.

14       Further, Perry recently completed its 6th refueling outage in 41 days, the shortest  
15       refueling outage in the Unit's history. This represents a 46% improvement over Perry's  
16       5th refueling outage, which lasted 76 days.

17       Operating availability at Perry averaged 68.0% over the period 1988 through 1995, with  
18       93.3% availability in 1995 surpassing the previous high of 90.8% in 1991. Averaged  
19       over the life of the facility, Perry's operating availability compares favorably with the  
20       64% operating availability target referenced in Mr. Hughes' testimony. During the June  
21       through August summer peak period, when Duquesne's need for capacity is at the  
22       greatest, Perry's historic operating availability has averaged 82.4%.

1 In addition, the Nuclear Regulatory Commission has also recognized the improvements  
2 in Perry's operating performance and the prospect for continued improvement under cur-  
3 rent management. (See Systematic Appraisal of Licensee Performance ("SALP") 13 Re-  
4 port for the Perry Nuclear Power Plant (Report No. 50-440/94001); Letter of John B.  
5 Martin to Mr. Donald C. Shelton dated February 14, 1995.)

6 Q. What about Perry's O&M costs?

7 A. Again, there has been dramatic improvement. Perry's cost per MWH (18 month periods)  
8 decreased from \$49.66 as of December 31, 1994 to \$23.43 as of June 30, 1997, a 53%  
9 improvement. Perry's non-fuel O&M costs decreased from \$170 million in 1994 to \$134  
10 million in 1996, a 21% drop, and are expected to decline to \$121 million in 1997.

11 Q. What are these improvements attributable to?

12 A. Perry has spent considerable sums of money over the past few years to improve its  
13 infrastructure and operating systems. It has made numerous management changes and  
14 taken other steps to improve its performance and lower its costs. These actions, including  
15 the "Perry Course of Action" and "Perry Plan for Excellence," appear to be having  
16 positive results.

17 Q. Have rates been increased to pay for these extra costs?

18 A. No, as previously discussed, the capital costs were expensed and ratepayers have been  
19 protected from adverse energy cost impacts and, indeed, receive the benefits of positive  
20 impacts on energy costs.

21 Q. Why did Duquesne intervene in Cleveland Electric Illuminating Company's 1995 rate  
22 case?

1 A. CEI is the operator of the Perry Plant. We were concerned over the operating experience  
2 at Perry in 1993 and 1994. We believe that our actions had the effect of continuing  
3 pressure on Cleveland Electric to reduce Perry's operating costs and improve its perfor-  
4 mance.

5 Q. What are the future cost and operating projections for the Perry Plant?

6 A. The operator of the Perry Station has projected achieving the following key performance  
7 goals by the year 2000: 1) reduction in total direct annual O&M expenditures from \$168  
8 million in 1995 to \$101 million; 2) non-fuel O&M costs will be reduced from 1.84 cents  
9 per KWH to 1.00 cent per KWH; 3) the plant availability factor will be increased from  
10 the 1995 level of 94.2% to 97.8%; 4) the plant capacity factor will be increased from  
11 86.9% to 95.3%; 5) the forced outage rate will be reduced from 21 days per year to 8 days  
12 per year; 5) the plant refueling cycle will be increased from an 18 month to a 24 month  
13 cycle; and 6) refueling outage duration will be reduced from 76 days to 40 days.

14 Q. Is the Perry Plant used and useful in providing utility service to the public?

15 A. Yes. The Perry plant has clearly been used and useful since the initiation of commercial  
16 operation in 1987 and will continue to be used and useful in the future. Specifically, the  
17 Perry Plant has been used and useful for the following reasons:

18 *1.) Perry has provided capacity in meeting the needs of retail customers.*

19 The Perry Power Plant has provided 161 MW of summer rated capacity and 164  
20 MW of winter rated capacity since the facility achieved commercial operation  
21 status in November, 1987. Perry currently represents 5.8% of Duquesne's active  
22 summer and winter capacity line-up. Perry was on-line meeting customer

1 capacity needs during the Duquesne all-time system peak of 2,666 MW estab-  
2 lished during the summer of 1995, and Perry was an important generating asset  
3 during the capacity shortage in the power supply crisis of January 1995. Since the  
4 facility achieved commercial operation status in November 1987, Perry has been  
5 on-line meeting customer capacity needs more than 80% of the hours during  
6 Duquesne's critical annual summer peak period of June through August.

7 **2.) *Perry has provided energy in meeting the needs of Duquesne's retail***  
8 ***customers.***

9 The Perry Power Plant, while providing 5.8% of Duquesne's active capacity, has  
10 provided, over the life of the facility, an average of 909,901 MWH of energy  
11 output annually, representing an average of 7.2% of the total annual energy needs  
12 of Duquesne's retail customers. In 1995 Perry provided 1,255,429 MWH of  
13 energy output, 9.5% of the total energy needs of retail customers. In 1994, despite  
14 an extended refueling outage, Perry met 4.9% of the total energy needs of retail  
15 customers. In 1993, despite a series of forced outages, Perry met 4.3% of the total  
16 energy needs of retail customers.

17 **3.) *The lifetime operating availability of Perry Unit 1 compares favorably***  
18 ***with the 1987 rate case projections and with industry averages.***

19 Operating availability at Perry averaged 68.0% over the period 1988 through  
20 1995, with 93.3% availability in 1995 surpassing the previous high of 90.8% in  
21 1991. Averaged over the life of the facility, Perry's operating availability com-  
22 pares favorably with the 64% operating availability target referenced in Mr.

1 Hughes' testimony. During the June through August summer peak period, when  
2 Duquesne's need for capacity is at the greatest, Perry's historic operating availabil-  
3 ity has averaged 82.4%.

4 **UNAVOIDED NUCLEAR PLANT COSTS UNDER**  
5 **AN EARLY SHUT DOWN SCENARIO**  
6

7 Q. What is the purpose of this portion of your testimony?

8 A. I will provide rebuttal testimony to certain portions of the direct testimony of Matthew I.  
9 Kahal, representing the Office of Consumer Advocate, Christopher D. Seiple, represent-  
10 ing the City Of Pittsburgh, and others. Specifically, I will rebut their contention that all of  
11 the site-related costs associated with the Perry Nuclear Power Plant could all be avoided  
12 if the unit were shut down prematurely. I will address fuel costs, O&M costs, capital  
13 expenditures, and decommissioning costs. Mr. O'Brien will address in his rebuttal testi-  
14 mony whether certain corporate costs can be avoided if the unit were closed early.

15 Q. These interveners in their direct testimony have advocated the early closure of certain of  
16 Duquesne's's generating units, including Perry. What is Duquesne's ownership interest in  
17 the Perry Plant?

18 A. Duquesne owns 13.74% of Perry.

19 Q. Who owns the rest of the unit?

20 A. Ohio Edison owns 30%, Cleveland Electric Illuminating has a 31.11% interest, Toledo  
21 Edison has a 19.91% interest, and Pennsylvania Power owns 5.24% of the plant.

22 Q. Are these companies known as the CAPCO companies?

23 A. Yes.

1 Q. Do the CAPCO companies jointly own any other generating units?

2 A. Yes. There are several jointly-owned units.

3 Q. Who operates Perry?

4 A. Cleveland Electric Illuminating (CEI) operates the Perry Plant on behalf of the other  
5 CAPCO companies.

6 Q. As operator of the plant, does CEI have sole discretion in making all decisions regarding  
7 the plant?

8 A. No. CEI makes decisions regarding the day to day operations of the plant; however,  
9 major decisions regarding the plant require the unanimous agreement of CAPCO.

10 Q. Could CEI unilaterally close Perry?

11 A. No. CEI could not take this action on its own. It would be required to obtain the agree-  
12 ment of the other CAPCO companies before shutting the plant down.

13 Q. Could Duquesne unilaterally close Perry?

14 A. No, for the same reason.

15 Q. Are there any contracts that govern the operations and decisions regarding Perry?

16 A. Yes. There is the Basic CAPCO Agreement, which governs the overall CAPCO arrange-  
17 ments. There also is a specific Perry Operating Agreement.

18 Q. Do these contracts specify that unanimous agreement among the CAPCO companies is  
19 required to prematurely close a plant?

20 A. Yes.

21 Q. Do these contracts contain any language regarding the sharing of operating and capital  
22 costs among the owners?

- 1 A. Yes. They specify that the non-operator owners, such as Duquesne in the case of Perry,  
2 must reimburse the operator owner for their pro rata shares of the operating and capital  
3 costs associated with the unit.
- 4 Q. Could Duquesne simply stop paying its share of the operating and capital costs associated  
5 with Perry?
- 6 A. No. Duquesne is contractually bound to the terms and conditions of the agreements  
7 governing the operation of the units. Duquesne is obligated to continue to pay its share of  
8 Perry's costs.
- 9 Q. Have the other owners of Perry indicated their willingness or desire to close the unit?
- 10 A. No.
- 11 Q. If the CAPCO companies were to agree to close Perry, would all of the associated costs  
12 be avoided immediately?
- 13 A. No. Certainly some of the costs could be avoided. For example, we would no longer  
14 perform refueling outages and could avoid those costs. We would also terminate any  
15 further capital expenditures for the unit. Most future fuel costs also could be avoided.
- 16 Q. What fuel related costs could not be avoided?
- 17 A. At the time of shutdown there would be a certain amount of nuclear fuel that would not  
18 have been consumed during operations. This is because most fuel is consumed over the  
19 course of two or three operating cycles. The cost of the fuel is expensed over the same  
20 period of time. Thus at any given time there is a balance of fuel costs not yet expensed.  
21 These costs would have to be written off at the time the plant was closed.
- 22 Q. What would those costs amount to?

1 A. That would depend on where in the fuel cycle we were when the unit was shut down. As  
2 an indication, Duquesne's share of unexpensed fuel at Perry at the end of 1997 is  
3 projected to be \$13.5 million.

4 Q. Could you sell the unused fuel to another utility?

5 A. No. The unused fuel resides in structures called fuel assemblies. The fuel inside each  
6 assembly would be partially consumed. Further, the assemblies are highly radioactive and  
7 could not be readily transported to another plant. Therefore, the fuel would not be of any  
8 use to another utility.

9 Q. Are there any other fuel related costs that could not be avoided?

10 A. Yes. We have fuel in the process of being fabricated. We would need to cancel the  
11 contracts for those services. We would also still be liable to the United States Department  
12 of Energy for the so-called uranium enrichment facilities decontamination and decommis-  
13 sioning surcharges.

14 Q. What would be the amount of these costs?

15 A. Again it would depend on when we cancelled the contract and just how much fuel was  
16 under contract for fabrication. As an example, it would cost Duquesne \$4.7 million to  
17 cancel the Perry fabrication contracts as of the end of 1997. The liability for the decon-  
18 tamination and decommissioning charges is \$1.2 million for Perry.

19 Q. You mentioned earlier that some operating costs could be avoided. Could all operations  
20 and maintenance expenses be avoided?

21 A. No, not immediately. I estimate that approximately 50% of O&M expenses could be  
22 eliminated shortly after plant closure. The other 50% would be needed to safely shut the

- 1 plant down, obtain required regulatory approvals, and prepare the plant for decommissioning. I estimate that these activities would take at least a year to complete. Thus I  
2 would expect that half of the unit's current operating expenses would continue for at least  
3 one year after plant shutdown. Thereafter site activities would be associated with  
4 decommissioning the unit.
- 5
- 6 Q. Are there any new, incremental costs that would be incurred if a unit were shut down?
- 7 A. Yes. We would incur severance costs for those employees at the unit who would be laid  
8 off. I have estimated Duquesne's share of those costs to be \$3.6 million at Perry in each  
9 of the first two years following shutdown.
- 10 Q. Are there any other incremental costs that would be incurred?
- 11 A. Yes. We would be required to write off the balance of the spare parts inventory at the  
12 plant. Based on current inventory levels, this would amount to \$4.0 million for  
13 Duquesne.
- 14 Q. Couldn't this inventory be sold to other plants?
- 15 A. No. My experience shows that there is no market for excess nuclear inventory. Most  
16 plants are conducting programs to reduce inventory levels. However, I have assumed a  
17 5% scrap value for the inventory.
- 18 Q. Would the basic requirements and actions needed to decommission a unit change  
19 significantly if it were closed prematurely?
- 20 A. Yes. Such costs would increase.
- 21 Q. Why would decommissioning costs increase?

1 A. There are two reasons. First, decommissioning costs would be paid sooner than if the unit  
2 operated until the end of its expected life.

3 Q. Why would this make a difference?

4 A. The funds in the decommissioning trusts would not have had an opportunity to accumu-  
5 late and earn a net return from fund investments.

6 Q. Aren't decommissioning costs expected to escalate over time?

7 A. Yes; however, trust earnings are expected to increase at a higher rate. This means that in  
8 real terms it would be more expensive to close a plant early and decommission it as  
9 compared to decommissioning the plant at the end of its operating life.

10 Q. You mentioned there were two reasons that these costs would increase. What is the  
11 second reason?

12 A. The unit's spent fuel would need to be removed from the reactor and stored in dry casks  
13 to permit the unit to be decommissioned. The fuel would be maintained on site in the  
14 casks until the Department of Energy (DOE) accepted shipment of the spent fuel. Various  
15 systems, such as security and radiological monitoring, would need to be maintained to  
16 ensure that the fuel was being stored safely. It is estimated that there would be an initial  
17 capital cost of \$20 million (\$2.7 million Duquesne share) to construct the storage  
18 facilities, and that it would cost \$.4 million per year (in current dollars) to maintain the  
19 spent fuel storage facilities.

20 Q. Wouldn't the spent fuel have to be maintained on site even if the unit operated until the  
21 expiration of its operating license?

1 A. Yes. However, much of the fuel could be stored in the existing spent fuel pool if the unit  
2 were allowed to operate until expiration of the operating license. If the unit is closed and  
3 decommissioned prematurely, dry cask storage will begin much earlier and be required  
4 for a longer period of time.

5 Q. What would be the difference in time dry cask storage would be required?

6 A. Using the current DOE schedule for accepting fuel, dry cask storage capability would be  
7 required for 34 years if a unit closes prematurely, as opposed to 15 years if the unit oper-  
8 ated to the end of its license.

9 Q. What would this mean in terms of cost?

10 A. This means that early shut down of a unit would add 19 years of dry cask storage costs at  
11 \$.4 million per year.

12 Q. Please summarize this portion of your testimony.

13 A. Early shutdown of a unit does not eliminate all of its associated costs, and in fact adds  
14 certain new costs. It is simplistic and inaccurate for the intervenors to argue that a unit's  
15 costs can all be avoided if it is shut down prematurely.

16 **REBUTTAL OF MR. KAHAL'S TESTIMONY**

17 Q. Mr. Kahal contends that Perry and Beaver Valley 2 are uneconomic and should be shut  
18 down. He believes that allowing those plants to operate would cause "ratepayers to  
19 subsidize operating losses on these plants during the transition period." He claims that  
20 "Duquesne could save more than \$200 million in net operating expenses, after accounting  
21 for the added cost of purchasing replacement power." Do you agree with Mr. Kahal's  
22 contentions?

1 A. No. As Mr. Clayton shows in his rebuttal testimony, there are no savings from closing  
2 these plants early. Mr. Kahal offers no support for his calculation of the \$200 million in  
3 purported savings. As I have shown above, there are numerous costs that cannot be  
4 avoided in the event of an early plant shut down.

5 Q. Mr. Kahal also believes that future plant O&M costs should be reduced to reflect  
6 assumed productivity gains, and proposes a 10% reduction in those costs. Do you agree  
7 with Mr. Kahal's view?

8 A. No. Future productivity gains for the nuclear plants have already been reflected in  
9 projected O&M and capital costs. Costs were fixed beginning in 2002 because it is not  
10 responsible to assume further gains that far out into the future. Significant improvements  
11 in plant costs have already been achieved in recent years. There are too many uncertain-  
12 ties associated with future regulatory requirements, equipment degradation, technology  
13 issues, price inflation and other factors that can influence future costs. These uncertain-  
14 ties would tend to offset any additional productivity gains. It would be speculative and  
15 irresponsible to project productivity gains beyond what Duquesne has already reflected in  
16 its calculations. Mr. Kahal has provided no specific evidence to support his position that  
17 future productivity gains are necessary. His proposal to infer a 10% productivity gain is  
18 arbitrary and the Commission should not accept Mr. Kahal's adjustments.

#### 19 **NUCLEAR DECOMMISSIONING COSTS**

20 Q. Mr. Catlin suggests that the contingency in the nuclear decommissioning calculations  
21 should be lowered to 10%. Do you agree with this proposal?

1 A. No. Mr. Catlin provides no evidence to support the adequacy of a lowered contingency.  
2 In fact, Environmentalists witness Biewald correctly notes that the Company's nuclear  
3 decommissioning cost obligation is "large, very uncertain" and that decommissioning  
4 expense estimates have "out paced inflation by about 10% per year." He goes on to state  
5 that, "Dismantling large, highly radioactive nuclear units is a large, complex undertaking  
6 for which experience is currently quite limited, and regulations continue to evolve....Any  
7 current estimate of nuclear decommissioning costs is subject to considerable uncertainty  
8 – technical, economic, and regulatory." These arguments support the need for a signifi-  
9 cant contingency factor in the decommissioning cost estimates. The Commission should  
10 reject Mr. Catlin's argument for a lower contingency factor.

11 Q. Do you wish to rebut any of Mr. Biewald's direct testimony concerning nuclear decom-  
12 missioning costs?

13 A. Yes. Mr. Biewald asserts that the Company's decommissioning liability is to some extent  
14 within the control of the plant owner, and that the Company has not adequately taken  
15 steps to mitigate decommissioning costs. Decommissioning costs are largely attributable  
16 to the design of the plant, meaning how much concrete, piping, and other materials were  
17 used to construct the unit. Decommissioning costs are also driven by the cost to dispose  
18 of low level radioactive waste and the labor costs to conduct the decommissioning  
19 activities. None of these costs are determined by how a unit is operated. Nor are they  
20 determined by how long the unit is operated. Thus Mr. Biewald is incorrect in his  
21 assertions that decommissioning costs are determined by how a plant is operated.

1 I would also point out that the Company has attempted to mitigate decommissioning  
2 costs by seeking to invest decommissioning funds in investments that will maximize trust  
3 fund earnings and therefore minimize the costs to the ratepayers. Also, the Company  
4 plans a strategy of timing the decommissioning of the Beaver Valley units so as to  
5 achieve the economies of scale of decommissioning two units at the same time, rather  
6 than separately. Again, this minimizes the costs to ratepayers. Finally, the Company  
7 unilaterally increased its contributions to the decommissioning trust funds. This action  
8 funds the trusts more rapidly and allows the trusts to grow faster as the result of returns  
9 earned on the fund investments. Again, Mr. Biewald errs in his conclusions.

10 Finally, Mr. Biewald comments that decommissioning costs should be the responsibility  
11 of the Company because it has not operated the units as "cleanly" as possible. He  
12 proposes that such costs be treated as operating costs. This is a ridiculous statement. I  
13 would be very interested in knowing how Mr. Biewald would operate a nuclear plant  
14 without contaminating major portions of the plant. As I stated above, once a plant has  
15 begun operations, the effort to decommission the unit has been determined. Total costs  
16 are therefore after determined by the rate of inflation, labor costs and waste disposal  
17 costs. These are factors that are beyond the Company's control and are independent of  
18 the continued operation of the plant.

19 Q. Are there any other matters you wish to discuss?

20 A. Yes. I am sponsoring certain revised exhibits to my direct testimony. These exhibits  
21 were circulated to the parties on October 16, 1997 as part of Duquesne's corrections to its

1           stranded cost calculations. For convenience, the entire package of revisions is included in  
2           Duquesne's rebuttal case as Ex. DJC-21, including my revised exhibits.

3        Q.    Does this conclude your testimony?

4        A.    Yes.

**Duquesne Statement No. 12-R**

**BEFORE THE  
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**DUQUESNE LIGHT COMPANY  
DOCKET NO. R-00974104**

**Rebuttal Testimony  
of  
Jeff D. Makhholm, Ph.D.**

**Contents:**

**Response to Intervenor Testimony Regarding Cost of Capital  
and Other Related Issues**

1    **I.     INTRODUCTION**

2    Q. What is your name?

3    A. Jeff D. Makholm.

4    Q. Are you the same Jeff D. Makholm who submitted direct testimony in this proceeding?

5    A. Yes.

6    Q. What is the purpose of your rebuttal testimony?

7    A. My purpose in providing rebuttal testimony is to respond to the testimony of Eric Van Jeschke  
8       testifying on behalf of the Office of Trial Staff. I will also have comments on issues of cost of  
9       capital as they appear in the testimony of Matthew Kahal, testifying on behalf of the Office of  
10      Consumer Advocate and Jonathan D. Muehl, testifying on behalf of David Hughes.

11   Q. How is your testimony organized?

12   A. I will first summarize my rebuttal testimony with respect to each of the three witnesses for  
13      whom I have rebuttal comments. Then I will deal with each witness in order.

14   **II.    SUMMARY OF TESTIMONY**

15   Q. Please summarize your testimony.

16   A. I deal with three witnesses in my rebuttal testimony:

17       1. Mr. Van Jeschke produces a recommendation regarding rate of return that suffers from  
18         various problems. His calculations are obscure and resist replication, his use of data is  
19         highly subjective, and his financial calculations are unsupported by a careful application  
20         of theoretical methods. His "reasonable range" (9.5 to 10.5 percent) looks unreasonable  
21         on its face, given the returns granted by other Commissions around the country.

22       2. Mr. Kahal uses a rate of return of 10 percent in his testimony without any support or  
23         justification of his own (other than the out-of-context fact that such a number was used in  
24         another case). Further, he recommends departures from the traditional treatment of certain  
25         debt costs, to the unjustified detriment of Duquesne.

26       3. Mr. Muehl presents testimony regarding missed opportunities for stranded cost mitigation,  
27         excessive dividends paid to Duquesne's stockholders and "sound public policy" that are

1            unsupported by analysis. His assertions about what Duquesne might have done reveal  
2            basic misunderstandings about the nature of utility ratemaking.

### 3        **III. REBUTTAL TO SPECIFIC WITNESSES**

4        Q. What is the purpose of this section of your testimony?

5        A. In this section, I will deal with the following witnesses: (1) Mr. Van Jeschke testifying for the  
6            Office of Trial Staff; (2) Mr. Kahal testifying on behalf of the Office of Consumer Advocate;  
7            and (3) Mr. Muehl, testifying on behalf of David Hughes.

#### 8            **A. Rebuttal to Mr. Van Jeschke**

9        Q. How is your rebuttal to Mr. Van Jeschke organized?

10       A. First, I will critique Mr. Van Jeschke's proxy group and address his specific criticisms of  
11           mine. Second, I will critique Mr. Van Jeschke's DCF calculation and address his specific  
12           criticisms of my DCF. Third, I will critique Mr. Van Jeschke's additional *Value Line*  
13           analysis. Lastly, I will demonstrate that the ROE he recommends is not reasonable compared  
14           to returns recently granted to electric utilities throughout the United States.

#### 15           **1. Proxy Groups**

16       Q. Are there problems with Mr. Van Jeschke's proxy group?

17       A. Yes. There are two. First, the financial risk criteria he uses for inclusion into the proxy group  
18           are not clear. Second, I conclude that some specific companies he includes should not be used  
19           in a DCF calculation.

20       Q. Why do you say Mr. Van Jeschke's financial risk criteria are unclear?

21       A. Mr. Van Jeschke states plainly that only utilities from the eastern and central U.S. are included  
22           in the proxy group (though he provides no rationale for the importance of this criterion). He  
23           also is specific in the amount of nuclear generation required for inclusion into the group. In  
24           contrast, the only information he gives about the financial risk criteria is that included  
25           companies are "similar in financial risk."

1 Q. Why is that a problem?

2 A. Because we have no idea of what Mr. Van Jeschke means by similar. For example, total  
3 capitalization appears to be one of his criterion, since it is listed in OTS Exhibit No. 1,  
4 Schedule 3. The range of total capitalization varies from about \$1.5 billion (IES Industries) to  
5 \$14.4 billion (Unicom Corp.). Given DQE's capitalization of about \$3.2 billion, it is not clear  
6 how different in capitalization a company would have to be, in order to be excluded from this  
7 group.

8 Another criterion, beta, raises similar questions. The range of betas is from .65 to .90, a  
9 substantial difference. It is unclear whether Mr. Van Jeschke eliminates some companies  
10 from his proxy group because they had betas beyond this range, or are all eastern and central  
11 utilities with 30 percent nuclear generation included in his proxy group? We simply do not  
12 know.

13 The other criteria: equity ratio, safety rank and financial strength share this same difficulty. It  
14 is impossible to tell whether Mr. Van Jeschke had specific financial criteria in mind that his  
15 proxy group members had to meet in order to be similar to the Company, or whether any  
16 company that met only the location and nuclear generating criteria were included in the group.  
17 If the latter is true, then the discussion of financial risk is irrelevant, since all companies were  
18 included regardless of their performance on the risk criteria.

19 Q. What specific companies in his proxy group do you conclude should not be included?

20 A. While Mr. Van Jeschke and I differ slightly over criteria like operating revenues from  
21 electricity and total capitalization, I do not hold these differences to be critical. However, Mr.  
22 Van Jeschke includes four companies, Atlantic Energy, Inc. Baltimore Gas & Electric Co.,  
23 Duke Power Co. and IES Industries, which are involved in potential mergers. I have stated  
24 previously that it is inappropriate to include such companies in a proxy group, as stock prices  
25 can be (and are) quite volatile during the period of the potential merger. Since this process  
26 can occur over a substantial period of time, a DCF calculation including merger companies  
27 would be less reliable. That is to say, the stock prices for such companies would tend to move  
28 for reasons related to the merger alone—not reasons reflecting the viability and growth

1 prospects of the firms themselves. Mr. Van Jeschke himself does not include DQE in his  
2 proxy group for this very reason. Therefore, I do not understand why he uses Atlantic Energy,  
3 Inc., Baltimore Gas & Electric Co., Duke Power Co. and IES Industries.

4 I also question the use of Boston Edison Co. and Rochester Gas & Electric Corp. in his proxy  
5 group since there is some concern in the investment press about the stability of their dividends  
6 (see Exhibit JDM - 16). Given that the DCF model assumes a growing dividend, I feel it  
7 unwise to include a company whose dividend is forecast to decrease. A decreasing dividend  
8 would violate a basic assumption of the DCF model.

9 Q. What specific criticisms of your proxy group made by Mr. Van Jeschke do you wish to  
10 address?

11 A. I wish to address two specific criticisms that Mr. Van Jeschke made concerning my proxy  
12 group. First, Mr. Van Jeschke objected to my proxy group because eight members did not  
13 have nuclear power generation. Second, Mr. Van Jeschke objected to my proxy group  
14 because 13 of the companies had purchased power for a large part of their generation. I will  
15 address each of these criticisms in turn.

16 Q. Is Mr. Van Jeschke correct in criticizing your proxy group because some of the proxy group  
17 members did not have nuclear power generation?

18 A. No. Mr. Van Jeschke noted that I addressed this subject in my direct testimony and then  
19 mischaracterized my opinion on the subject. "Dr. Makhholm makes this observation of his  
20 proxy group, however, does not believe it is an important fact in this case" (p. 42, ll. 5-6). I  
21 stated in my testimony that I regularly use nuclear power generation as a criterion, but opted  
22 not to in this case. This was because so many electric utilities are involved in mergers, and  
23 therefore, are not candidates for inclusion in my proxy group. I also noted in my testimony  
24 that nuclear facilities are generally viewed as increasing a utility's risk. In order to obtain a  
25 DCF result that was more reliable and stable, I chose to relax the nuclear power generation  
26 constraint.

27 I felt comfortable in doing so because relaxing this constraint produces a more conservative  
28 result, that is a result that would underestimate the true ROE—reflecting as it would a lower

1 risk group of non-nuclear companies. This is because nuclear power generation is viewed by  
2 the investment community—and Mr. Van Jeschke—as riskier than other forms of power  
3 generation. Therefore, I am somewhat surprised by Mr. Van Jeschke’s criticism. Had I been  
4 able to incorporate this criterion and been comfortable with the proxy group’s ability to  
5 produce a stable and reliable result, then my recommendation would have been higher.  
6 **Exhibit JDM - 17** shows a DCF calculation I performed, using data from the same time  
7 period I used in my direct testimony. I began with the proxy group of companies I used in my  
8 direct testimony, but I restricted myself to those companies who derive part of their electricity  
9 revenues from nuclear power generation. The resulting DCF return would have been **12.37**  
10 **percent**. I believed the addition of non-nuclear power electric utilities increased the stability  
11 and reliability of my recommended return because they increased the size of my proxy group.  
12 Mr. Van Jeschke, however, would appear from his testimony to find this higher, strictly  
13 nuclear proxy group, result more persuasive.

## 14 2. DCF Analysis

15 Q. What will you discuss in this section of your testimony?

16 A. I will critique Mr. Van Jeschke’s method of determining the dividend yield and growth rate.  
17 Then I will address some specific criticisms made by Mr. Van Jeschke with regard to my  
18 flotation cost adjustment in my DCF.

### 19 a. Dividend Yield

20 Q. Do you agree with Mr. Van Jeschke’s method of determining the dividend yield portion of the  
21 DCF formula?

22 A. No. Mr. Van Jeschke uses a dividend yield figure in his DCF model that will bias downward  
23 the dividend yield that the DCF model requires. The correct way to calculate the expected  
24 dividend payment over the next year is to observe the *past* four payments and multiply them  
25 by the expected dividend growth rate. Mr. Van Jeschke, on the other hand, observes the  
26 “current” dividend yield (the latest dividend multiplied by and divided by the 52-week  
27 average and the current stock price) and multiplies these figures by *half* of the expected  
28 growth rate to get next year’s dividend yield. This treatment of the dividend yield assures an

1 understatement, on average. **Exhibit JDM - 18** of my rebuttal testimony presents a paper I  
2 co-authored in 1992 entitled "Four Common Errors in Applying the DCF Model in Utility  
3 Rate Cases" in which I demonstrate how this method of calculating the dividend yield can  
4 lead to an incorrect result.

5 Q. Do you have any other disagreements with Mr. Van Jeschke's calculation of the dividend  
6 yield?

7 A. Yes. Mr. Van Jeschke failed to make an adjustment to account for the ex-dividend date  
8 phenomenon.

9 Q. Does Mr. Van Jeschke dispute the ex-dividend phenomenon?

10 A. That is not clear to me. Nowhere in his testimony does he deny that stock prices drop on the  
11 ex-dividend date. However, he indicates that the stock price change cannot be attributed  
12 solely to the ex-dividend phenomenon (page 43, ll. 15-16).

13 While it may be true that a change in stock price on any given day may not be attributed  
14 completely to any one factor, this does not prevent us from understanding phenomena that do  
15 occur with great regularity in the financial markets. In my direct testimony, I provided  
16 *academic evidence* (which Mr. Van Jeschke indeed called for) that the phenomenon exists.<sup>1</sup>  
17 This evidence demonstrates that the value of a share drops by an amount approximately equal  
18 to its dividend on the ex-dividend date.

19 A simpler and more common sense example demonstrates that the phenomenon must exist. If  
20 an investor had two shares of the same common equity, one that gave him the right to the next

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<sup>1</sup> The following references, found on page 22 of my direct testimony, discuss the ex-dividend date and provide evidence that the ex-dividend date phenomenon occurs in the financial markets: E. F. Brigham, *Financial Management Theory and Practice*, 3<sup>rd</sup> Edition, (New York: The Dryden Press, 1982), 687. Empirical evidence of this phenomenon can be found in articles written by J. A. Cambell and W. Beranek, "Stock Price Behavior on Ex-Dividend Dates," *Journal of Finance*, 10, 4, (December 1955), 425-429; D. Durand and A. M. May, "The Ex-Dividend Behavior of American Telephone and Telegraph Stock," *Journal of Finance*, 15, 1, (March 1960), 19-31; and E. J. Elton and M. J. Gruber, "Marginal Stockholder Tax Rates and the Clientele Effect," *Review of Economics and Statistics*, (February 1970), 68-74.

1 dividend and the other that did not, should he reasonably be willing to sell them at the same  
2 price? The answer is no. One share is worth more, by the value of the next dividend.<sup>2</sup>

3 The ex-dividend phenomenon is a valid phenomenon—theoretically explained and  
4 empirically verified. Mr. Van Jeschke recommends that we simply ignore it. Since the effect  
5 of the phenomenon is always to underestimate the true required return on equity, I conclude  
6 we must attempt to correct the bias. My ex-dividend date adjustment does just that.

7 Q. Do you agree with Mr. Van Jeschke that the adjustment is not necessary when using a 52-  
8 week average stock price?

9 A. No. Mr. Van Jeschke suggests that the ex-dividend phenomenon would somehow average  
10 out for seasonal or quarterly effects. This is untrue. As I stated and showed in my direct  
11 testimony (**Exhibit JDM-5**), the correct calculation can be approximated (to a high degree of  
12 accuracy in this case) by making *one-half* of the full adjustment for the group when a proxy  
13 group is used. That is, an adjustment that assumed that the ex-dividend date is 45 days away  
14 works virtually, on average for the group, as well as a specific adjustment for each company.  
15 The adjustment properly accounts for the ex-dividend date effect.

16 In sum, the effect is a fact of life in the stock markets. If one measured the stock price during  
17 the course of a quarter, the only time that the presence of the next dividend would not  
18 influence the stock price should be on the ex-dividend date itself. During the rest of the  
19 period, the company would be accruing earnings that investors would reasonably anticipate  
20 receiving at the quarter's end. In that event, the average ex-dividend adjustment over the  
21 period of the quarter would be about half of the next dividend and not zero as Mr. Van  
22 Jeschke opines.

23 As I stated, a complete discussion of the average ex-dividend date adjustment appears on page  
24 23 of my direct testimony and is demonstrated in **Exhibit JDM-5**.

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<sup>2</sup> **Exhibit 18** also includes a discussion of the ex-dividend date error.

1                   **b. Growth Rate**

2    Q. Do you agree with Mr. Van Jeschke's method of determining growth?

3    A. Mostly, no. I think it is important to state first that I agree with Mr. Van Jeschke's use of  
4       forward-looking analysts' forecasts of future growth. As my direct testimony indicates, I  
5       conclude they are the best estimate we have of what investors might expect future growth to  
6       be. However, I find Mr. Van Jeschke's discussion of historical vs. forecast growth rates  
7       ambiguous and his process of determining the growth rate highly subjective.

8    Q. Please explain.

9    A. Mr. Van Jeschke goes to a great deal of trouble to calculate historical growth rates for the  
10       companies in his proxy group. In fact, he computes four separate historical growth rates for  
11       each company. On page 29, lines 13-15 of his direct testimony, he says that he normally  
12       places the most emphasis on historical dividend growth when estimating the DCF cost of  
13       equity. Some three lines later in his testimony he says, "Most of the research evidence  
14       indicates that analysts' growth forecasts are superior to historically-oriented growth measures"  
15       (p. 29, ll. 18-19). If the research evidence does indeed suggest this—and I conclude that it  
16       does—then Mr. Van Jeschke has no basis for his "normal" reliance on historical data.

17       Mr. Van Jeschke states that he would be double counting the importance of historical data if  
18       he used it in this testimony, because historical data is accounted for in forecast growth. If true,  
19       this suggests that his normal estimates, that rely mostly on historical data, underemphasize the  
20       importance of analysts' forecasts.

21       I also wondered why Mr. Van Jeschke calculated the historical growth rates *at all*, given that  
22       he intended to use forecast growth rates. It gives the appearance that Mr. Van Jeschke had an  
23       acceptable growth rate in mind before he began his analysis and that he found a method of  
24       dismissing estimates that disagreed substantially with his preconceived growth rate.

25    Q. Are there any other examples of similar subjectivity?

1 A. Yes. One of his methods of determining historical growth yielded a growth rate of 4.09  
2 percent. He rejected it out-of-hand, saying that it was "...unlikely to be sustainable for the  
3 EBG (*electric barometer group*)" (page 30, line 16).

4 Further, Mr. Van Jeschke criticized my growth rate because one of the estimates, taken from  
5 analysts' forecasts, was 4.31 percent. He presented no methodological or empirical  
6 disagreement with the estimate. He simply stated that, "It is my opinion that a growth rate  
7 above 3.50 percent is not sustainable" (p. 45, ll. 8-9). He offered no rationale or evidence to  
8 support his opinion.

9 Mr. Van Jeschke cannot have it both ways. Either investor analysts' forecasts are good  
10 estimates of investor-expected growth, or they are not. By his own admission, research  
11 indicates they are better than historical growth methods. What we are trying to determine in  
12 this part of the proceeding is what *investors* require as a fair rate of return on equity.

13 Q. Why did you feel that Mr. Van Jeschke's method for determining growth was subjective?

14 A. Because it is impossible to understand exactly how he derives his specific estimates. Mr. Van  
15 Jeschke overwhelms us with the quantity of his estimates. He calculates compound, log-linear  
16 historical and forecast growth rates from multiple sources, and he computes their medians and  
17 means. All of these data points provide a patina of objectivity. But they are a thin veneer  
18 covering a process that is essentially subjective. The multitude of historical growth rates he  
19 calculated do not appear to be used at all in his recommended growth rate. Growth rates  
20 above 3.50 percent are summarily dismissed. Finally, it is not even clear how he uses the  
21 growth rates he finds acceptable to obtain his range of 2.50 percent to 3.50 percent.

22 In response to the question in his direct testimony that asks him to explain the *specific*  
23 judgment he exercised to determine the 2.50 percent to 3.50 percent range, Mr. Van Jeschke  
24 simply lists all of his growth calculations. He never specifically says how he obtains his  
25 range.

26 **c. DCF Result**

27 Q. Do you agree with the manner in which Mr. Van Jeschke establishes his DCF range of 9.50  
28 percent to 10.50 percent?

1 A. No.

2 Q. Why not?

3 A. It is another example of how Mr. Van Jeschke subjectively changes the results of his empirical  
4 work to produce a lower return. Using his own methodology, Mr. Van Jeschke obtained a  
5 DCF range of 9.59 percent and 10.62 percent (p. 31). Later, when asked what he believed a  
6 reasonable range to be, he indicated a range of 9.50 percent and 10.50 percent (p. 35). In  
7 moving down from 9.59 to 10.62 percent to 9.50 to 10.50 percent, Mr. Van Jeschke appears to  
8 simply have removed his "dividend yield adjustment" (p. 31), with no explanation at all.  
9 Although the loss is only 9 and 12 basis points in this one specific instance, the problem is  
10 that this subjective rearrangement occurs throughout the testimony and always to the  
11 Company's disadvantage.

12 Q. But doesn't Mr. Van Jeschke select the top of his range as his recommended return?

13 A. Yes, Mr. Van Jeschke tries to give the appearance of reasonableness in suggesting the higher  
14 return. But this comes after his previous subjective adjustments such as ignoring growth rates  
15 higher than 3.50 percent and arbitrarily reducing his DCF range.

16 Further, Mr. Van Jeschke's generosity raises some additional questions. He uses the  
17 Company's capital structure and senior debt rating as the reason for granting the higher part of  
18 his range. If these are important factors, why are they not more clearly a part of his proxy  
19 group criteria? For example, if the Company's current capital structure represents a special  
20 risk, then to be comparable, his proxy group should reflect it. Also, if the Company's BBB+  
21 senior debt rating truly suggests additional risk, his proxy group companies should share those  
22 characteristics as well. If these issues are truly important, I believe that they should be  
23 addressed in his proxy group criteria, before the opportunity exists for subjective adjustments  
24 to calculated results.

25 **d. Flotation Cost Adjustment**

26 Q. What specific criticism of your flotation cost adjustment would you like to address?

1 A. Mr. Van Jeschke claims that my flotation cost adjustment is not appropriate because the  
2 expenses were incurred in the past at the time of issuance and are now reflected in the market  
3 price of the common stock.

4 Q. Do you agree that the Company should not be compensated for the expenses?

5 A. Absolutely not. Mr. Van Jeschke is correct in stating that the Company incurred these costs at  
6 the time of issuance. He failed to note, however, that there are three ways a company can be  
7 fully compensated for these expenses. *First*, the Commission could allow the Company to  
8 recover these expenses automatically in the year they are incurred as an expense component of  
9 the revenue requirement (or the expense could be amortized over a number of years). This  
10 treatment would include issuance expenses as an expense, when they occur, to be deferred,  
11 amortized and collected from customers over a specified period agreeable to the Commission  
12 and the Company. This would even-out the collection of these expenses, and cushion their  
13 short-term impact on rates.

14 *Second*, the Commission could allow the issuance expense to be included in rate base (like the  
15 treatment of interest charges on construction work in progress). This would allow the  
16 Company to earn a return *on* the expenses, as opposed to a return *of* the expenses.

17 *Third*, the Commission could adjust the cost of capital upward over the life of the issue. This  
18 adjustment in effect allows the Company to earn a return *on* the issuance expenses, even  
19 though the expenses are not in rate base. The financial result and the revenue requirement are  
20 the same as for the second method. All three of these methods compensate the utility for the  
21 actual issuance expenses that were incurred.

22 The Commission, however, did not compensate the Company for the expenses of its issuances  
23 when they were incurred, or at any time thereafter. The result of this was a loss of value to the  
24 Company. Investors reacted to this loss of value by reducing what they were willing to pay  
25 for the Company's shares. Nowhere in his direct testimony does Mr. Van Jeschke claim that  
26 selling and issuance costs are anything other than legitimate costs. And nowhere does he  
27 provide evidence that a company should not be compensated for legitimate costs it incurs. It is  
28 clear, therefore, that the Company deserves to be compensated for these expenses. My

1 flotation cost adjustment is an effort to give back to the Company, what would otherwise be  
2 taken away. Mr. Van Jeschke is simply wrong to imply that just because legitimate and  
3 verifiable costs have occurred in the past (costs that have never been recovered), they should  
4 be ignored.

5 **3. Mr. Van Jeschke's Additional *Value Line* Analysis**

6 Q. What will you address in this section of your testimony?

7 A. Mr. Van Jeschke performed an additional analysis using *Value Line Investment Survey* to  
8 support his recommendation.

9 Q. Do you agree with his methodology?

10 A. No. Mr. Van Jeschke uses the "Annual Rates" found in a box on the left-hand side of the  
11 *Value Line* page. I do not use these "Annual Rates" because they incorporate some historical  
12 data to form the *Value Line* forecast.

13 Q. Please explain.

14 A. The *Value Line* annual rates used by Mr. Van Jeschke incorporate data from 1995 and 1996 to  
15 forecast growth into the year 2001. I calculate a fully forecast growth rate and feel it is  
16 superior to using historical data. Mr. Van Jeschke seemed to agree with me when he noted  
17 that research indicated that forecasts are superior to historical growth rates. Mr. Van Jeschke  
18 also felt that using historical data would represent double counting, since historic data is  
19 already fully accounted for in forecast methods.

20 Q. Is there any other reason that you don't use these "Annual Rates"?

21 A. Yes. When the near future is expected to depart from the recent past, these "Annual Rates"  
22 can produce unreliable and unusable results. For example, if the company in question has  
23 experienced rapid growth in the recent past and anticipates slower growth in the near future,  
24 the "Annual Rates" will underestimate future growth. In certain instances it will even predict  
25 negative growth rates. Therefore, I conclude that the fully forecast growth rates are superior  
26 to the *Value Line* "Annual Rates."

1 Q. Did you observe any problems in Mr. Van Jeschke's analysis?

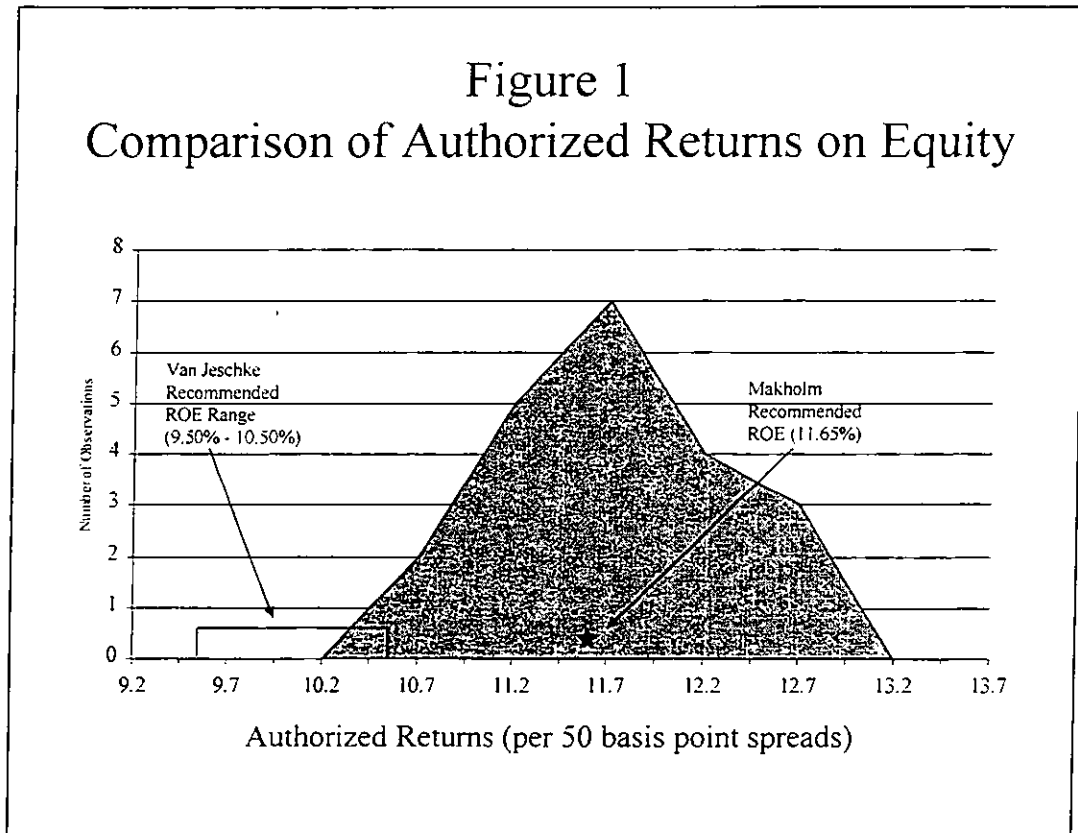
2 A. Yes. Four of Mr. Van Jeschke's proxy group members showed zero dividend growth for the  
3 future (Dominion Resources, Inc., IES Industries, PP&L Resources and Rochester Gas &  
4 Electric Corporation) while two companies showed *negative* growth rates (Atlantic Energy,  
5 Inc. and PECO Energy Company). Inasmuch as dividend growth plays a part in his additional  
6 analysis, it is inappropriate to include these six companies in his proxy group, because the  
7 DCF model assumes a constantly growing dividend.

8 I could not replicate Mr. Van Jeschke's analysis due to the difficulty of obtaining the exact  
9 data he used. However, I did use his proxy group to calculate annual DCF using my model  
10 and my data. When all thirteen companies from Mr. Van Jeschke's proxy group were used,  
11 the DCF result was 11.24 percent—higher than Mr. Van Jeschke's recommended return of  
12 10.50 percent. However, there were three companies which had negative EPS growth  
13 according to *Value Line Investment Survey* and *Compustat* (Boston Edison Co., Rochester Gas  
14 & Electric Corp. and Unicom Corp.). When these three companies are eliminated from the  
15 proxy group, the DCF result is 11.76 percent—still higher than Mr. Van Jeschke's  
16 recommended return, but also higher than my recommended return of 11.65 percent.

17 **4. The Unreasonableness of Mr. Van Jeschke's Recommended Return**

18 Q. Do you have any other evidence that his DCF result is unreasonably low?

19 A. Yes. I have submitted his recommended DCF result of 10.50 percent to the same  
20 reasonableness check as my recommended return. **Figure 1** below, taken from my direct  
21 testimony (p. 31), shows the range of electric utilities' returns on equity authorized by  
22 regulatory commissions throughout the country between April 1995 and March 1997. The  
23 figure also shows the number of decisions associated with each authorized return. As the  
24 figure shows, my recommended return of 11.65 rests almost in the middle of the distribution.  
25 I have also inserted Mr. Van Jeschke's recommended return into the figure. A return on  
26 equity of 10.50 percent clearly falls into the extreme low tail of the figure. This suggests that  
27 Mr. Van Jeschke's recommendation is unreasonably low compared to recent authorized  
28 returns.



1

2

**B. Rebuttal to Mr. Kahal**

3

Q. What are your rebuttal comments on the testimony of Mr. Kahal?

4

A. I have two comments. The first pertains to Mr. Kahal's unsupported use of 10 percent as a reasonable return on equity to use for Duquesne in this case. The second concerns the way in which Mr. Kahal has altered traditional practices in Pennsylvania regarding the recovery of acquisition costs for debt.

7

8

Q. What comments do you have regarding Mr. Kahal's use of 10 percent as the rate of return to use for Duquesne?

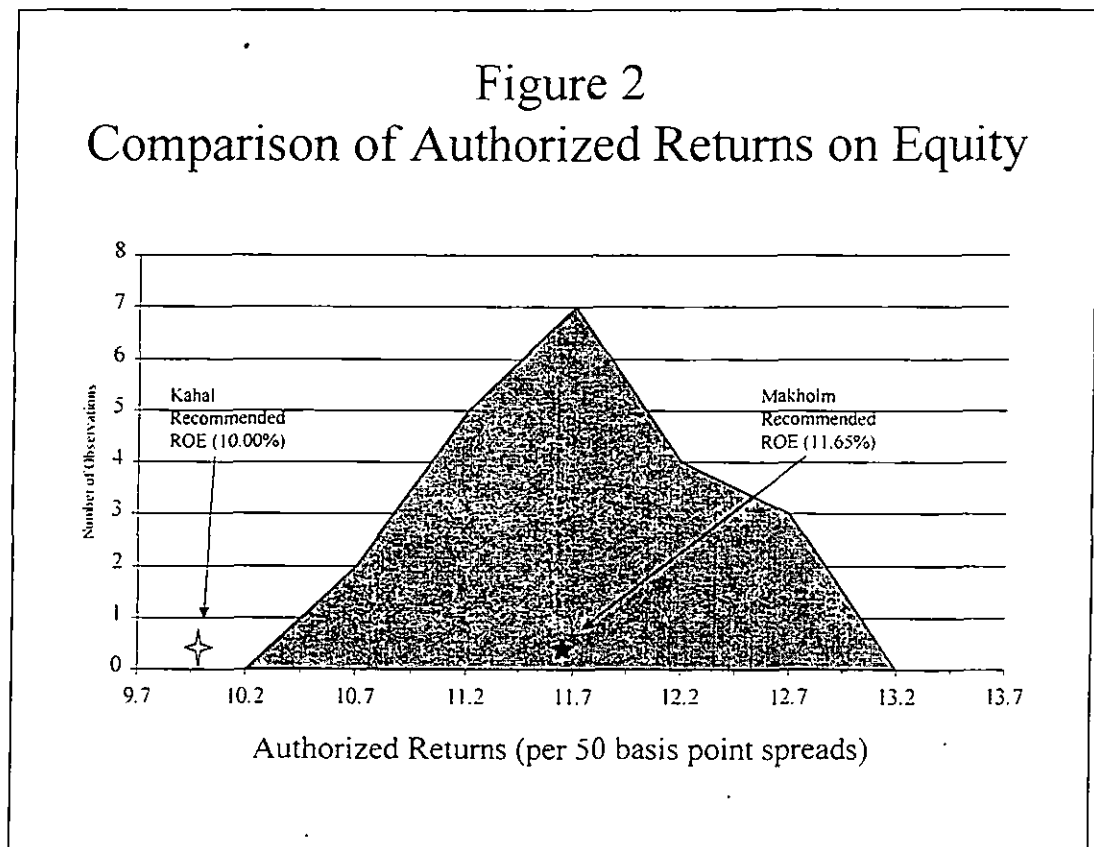
9

10

A. The 10 percent number he uses is inappropriate in this case. Mr. Kahal offers no support for his number, other than using a reference to the securitization case of PECO Energy. He introduces no evidence and makes no attempt to argue that circumstances in that PECO case, or the reasoning the Commission applied in order to arrive at such a figure in a different case,

13

1 at a different time, are transferable to this case. As such, other than a bald assertion that 10  
 2 percent "should apply to Duquesne as well" (p. 26), there is no support for that figure at all in  
 3 Mr. Kahal's testimony. That assertion should not be considered as evidence on the cost of  
 4 capital for Duquesne or any electric utility like Duquesne. Furthermore, as **Figure 2** shows,  
 5 Mr. Kahal's 10 percent figure simply looks unreasonable compared to what other  
 6 Commissions around the country have found regarding the fair rate of return on equity.



7

8 Q. What about the issue of unamortized debt acquisition costs?

9 A. As explained in the rebuttal testimony of Donald J. Clayton, unamortized debt costs represents  
 10 underwriters' discounts, premiums and expenses paid by Duquesne to issue and refinance  
 11 debt. In other words, they are real-world expenses that Duquesne—and every other such  
 12 utility—incur in order to place its debt securities with investors. The expenses are always  
 13 there, they are prudently incurred, and every jurisdiction has ways of recovering them.

1 Q. How are such debt issuance costs normally treated?

2 A. They are normally treated by subtracting such expenses and discounts from the principal  
3 amount of a debt issue in order to derive "net proceeds." The actual interest expense is then  
4 calculated as a percent of the "net proceeds" (which makes it a bit higher than if calculated on  
5 the principal amount) in order to amortize the expenses and discounts over the life of the  
6 issue.

7 Q. Have you performed such calculations yourself as part of other cost of capital assignments in  
8 the past?

9 A. Yes. They represent a very common way of handling such costs.

10 Q. What is the issue in this case regarding such costs?

11 A. Mr. Kahal (in conjunction with his colleague Mr. Thomas S. Catlin) is attempting to change  
12 the traditional way of dealing with such expenses and discounts in a way that lowers  
13 Duquesne's overall rate of return vis-a-vis what Duquesne would receive under traditional  
14 treatment.

15 Mr. Clayton has proposed to recover the old, post-2005 expense (*i.e.*, the portion that would  
16 normally have been recovered in the normal way after that date) before 2005. That is a  
17 reasonable and consistent treatment, in my opinion. Messrs. Kahal and Catlin propose to treat  
18 the post-2005 recovery as a regulatory asset, which would lower the cost of debt in the return  
19 calculations, as well as increase the apparent leverage. Both effects lower the return to  
20 Duquesne, as Mr. Clayton correctly states, and both are unwarranted departures from the  
21 traditional practice of dealing with such issuance costs. I thus recommend that Mr. Clayton's  
22 approach to this issue be retained, and that Messrs. Kahal's and Catlin's deviation from  
23 traditional practice be rejected.

24 **C. Rebuttal to Mr. Muehl**

25 Q. What is Mr. Muehl's testimony?

1 A. Mr. Muehl presents some calculations that purport to show that Duquesne has transferred  
2 "wealth" from rate-payers to stockholders "in excess of that which would be reasonable for a  
3 regulated utility" (p. 6).

4 Q. Do you agree with Mr. Muehl?

5 A. No. He confuses a number of concepts central to utility ratemaking, and he uses market data  
6 that is not pertinent to the question of the cost of capital to which Duquesne is entitled by law.  
7 He makes inconsistent recommendations regarding what he thinks Duquesne might have done  
8 to mitigate stranded costs in the past, and he injects a "psychological point of view" (p. 3) into  
9 how the company should have acted to justify its dividend policy. He also makes a mistake in  
10 asserting that Duquesne should operate on a "cash flow" basis rather than on the basis of a fair  
11 return on the company's invested capital (tied to that capital's cost) which has guided the  
12 regulation of public utilities in the United States at least since the *Hope Natural Gas* Supreme  
13 Court decision of 1944.

14 Mr. Muehl apparently believes that Duquesne could have done more to mitigate its stranded  
15 costs, and that Duquesne could live with some sort of "enforced rate reductions." However,  
16 because his beliefs are based neither on a realistic view of how shareholders are compensated  
17 for the use of their capital nor how actual utility rates are made, he provides no  
18 recommendations upon which the Commission could possibly act.

19 Q. Please explain.

20 A. Mr. Muehl's ultimate conclusions are based on examining a single 10-year holding period for  
21 Duquesne's stock. Besides the fact that Mr. Muehl selectively uses a period of time designed  
22 to maximize the returns to Duquesne's shareholders, he never confronts the irrelevance of  
23 such comparisons in the context of rate-setting. Utilities and Commissions do not set rates for  
24 utilities on the basis of relative movements in stock prices or on investor returns to holding a  
25 particular stock. They set rates on the basis of *costs*, one of which is the cost of capital. His  
26 data is irrelevant to rate-setting cases.

27 Mr. Muehl's inconsistencies regarding the rate-setting process can be characterized by his  
28 apparently equivalent view of accelerated depreciation and write-downs. He states (p. 3): "[a]

1 simple and effective way for a company to mitigate its stranded costs is to accelerate the  
2 depreciation of its stranded assets, or to simply write down the value of those assets." He does  
3 not appear to realize that depreciation expense is a traditional part of utility rates, and that  
4 accelerating depreciation will raise those rates, not lower them. His statements regarding  
5 Duquesne's psychological point of view (p. 3) also relate to his mistaken notions about how  
6 regulators handle depreciation (as though it were not a part of rates).

7 He also confuses "cash flow" with cost recovery. He states: "it seems reasonable to expect  
8 that the lower rates [set by enforced rate reductions due to accelerated depreciation or write-  
9 downs] set by the regulators would still allow the company sufficient cash flow to continue  
10 serving its customers" (p. 4). Mr. Muehl does not appear to realize that rates are based on  
11 actual costs, including the cost of capital, not some notion of future cash flow needs. Utilities  
12 in the United States do not set their rates on a "cash flow" basis.

13 Q. What are your summary comments related to Mr. Muehl's testimony?

14 A. I conclude that he has basic misunderstandings about how the regulatory process works or  
15 how rates are set. As such, I do not think his testimony has any usefulness in this proceeding.

16 Q. Does this conclude your rebuttal testimony?

17 A. Yes.

<b>BOSTON EDISON</b> NYSE-BSE		RECENT PRICE	26	P/E RATIO	9.8 (Trailing: 10.3 Median: 11.0)	RELATIVE P/E RATIO	0.60	DIV'D YLD	7.2%	VALUE LINE	165								
<b>TIMELINESS</b> (Rating: Prep Perform. - Also Need 12 Mos.)	4	High:	27.9	28.0	18.8	22.1	20.3	24.9	28.3	32.6	29.9	29.5	30.1	27.4	Target Price Range	2000	2001	2002	
<b>SAFETY</b> (Scale: 1 Highest to 5 Lowest)	3	Low:	21.2	16.8	12.5	15.4	16.5	16.3	22.3	26.4	21.5	23.1	21.8	24.6					
<b>BETA</b> .70 (1.00 = Market)																			
<b>2000-02 PROJECTIONS</b>																			
High	30	Gain	+15%	Return	10%														
Low	20	Gain	-25%	Return	2%														
<b>Insider Decisions</b>																			
to Buy	0	to Sell	0	to Buy	0	to Sell	0	to Buy	0	to Sell	0	to Buy	0	to Sell	0	to Buy	0	to Sell	0
<b>Institutional Decisions</b>																			
to Buy	44	to Sell	48	to Buy	46	to Sell	39	to Buy	39	to Sell	39	to Buy	39	to Sell	39	to Buy	39	to Sell	39
<b>Options: None</b>																			

1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	VALUE LINE PUBL. INC.	100-02
38.91	36.01	35.30	41.81	37.14	29.95	31.56	31.74	32.95	32.27	31.39	31.54	32.84	34.01	33.92	34.35	36.30	35.00	35.00	Revenue per sh	35.00
4.48	4.47	5.41	5.67	6.75	5.55	4.95	5.13	5.73	5.36	5.75	5.88	5.95	6.59	6.23	7.31	7.50	7.40	7.40	Cash Flow per sh	7.75
2.08	1.59	1.80	2.43	2.52	2.58	1.97	1.86	1.90	1.90	1.96	2.10	2.28	2.41	2.08	2.61	2.65	2.65	2.65	Earnings per sh A	2.50
1.40	1.41	1.48	1.56	1.67	1.75	1.80	1.82	1.75	1.54	1.60	1.66	1.72	1.78	1.84	1.88	1.88	1.88	1.88	Div'd Decl'd per sh B	1.88
4.81	4.65	4.99	8.39	6.74	4.73	6.28	6.47	6.72	6.68	5.09	5.16	5.63	4.85	4.15	4.25	2.80	3.10	3.10	Cap'l Spending per sh	3.25
16.01	15.86	16.10	16.85	17.71	19.38	19.37	19.38	16.73	17.22	17.92	18.77	19.42	20.11	20.61	21.05	21.98	22.45	22.45	Book Value per sh C	24.50
28.44	29.33	30.29	31.50	32.42	36.91	37.43	37.69	38.53	39.01	42.05	44.78	45.13	45.54	48.00	48.51	48.51	48.51	48.51	Common Sh Outd'g D	48.51
5.2	7.1	7.6	5.9	7.8	9.8	11.4	8.5	9.3	1.5	10.6	11.9	13.1	10.7	12.3	9.7	9.7	9.7	9.7	Bold figures are	10.5
6.3	7.8	8.4	5.5	6.3	8.8	7.8	7.1	7.0	4.5	8.8	7.2	7.7	7.0	8.2	8.1	8.1	8.1	8.1	Avg Ann'l P/E Ratio	7.5
12.0%	12.6%	10.6%	11.0%	8.5%	7.0%	8.0%	11.5%	9.9%	8.5%	7.7%	6.8%	5.8%	6.9%	7.2%	7.4%	7.4%	7.4%	7.4%	Avg Ann'l Div'd Yield	7.3%

**CAPITAL STRUCTURE as of 3/31/97**  
 Total Debt \$1379.8 mil. Due in 5 Yrs \$592.8 mil.  
 LT Debt \$1058.8 mil. LT Interest \$94.8 mil.  
 (LT interest earned: 3.4x)  
 Leases, Uncapitalized Annual rentals \$22.8 mil.  
 Pension Liability None in '96 vs. \$42.7 mil. in '95  
 Pfd Stock \$211.0 mil. Pfd Div'd \$15.3 mil.  
 1,230,000 shs: 4.25%-8.25%, cum., redeemable at  
 \$102.80-\$103.825. Incl. 380,000 shs, 7.27%, cum.,  
 subj. to mand. redemp. at \$102.91. Excl. redemp.  
 & insurance costs & pfd. stock due within one year.  
 Incl. 400,000 shs. 8.25% redeemed 6/1/97.  
 Common Stock 48,514,973 shs.  
 as of 5/12/97

<b>ELECTRIC OPERATING STATISTICS</b>			
% Change Retail Sales (RWH)	1994	1995	1996
Avg Indus. Use (MWH)	+1.7	+1.2	+2.9
Avg Retail Use (MWH)	942	952	1005
Avg Retail Rev. on RWH (\$)	9.28	9.60	9.59
Capacity to Peak (MW)	3484	3466	3385
Peak Load Summer (MW)	2798	2785	2703
Annual Load Factor (%)	58.9	60.0	63.4
% Change Customer Imp.	+7	-3	+6

<b>ANNUAL RATES</b>			
of change (per sh)	10 Yrs	5 Yrs	Em'd '96-'98 to '00-'02
Revenues	-3%	1.0%	.5%
"Cash Flow"	1.0%	3.0%	2.5%
Earnings	-5%	5.5%	1.0%
Dividends	1.0%	2.5%	.5%
Book Value	1.5%	3.5%	5.0%

<b>QUARTERLY REVENUES (\$ mil.)</b>					
Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1994	377.4	368.7	449.1	353.4	1548.6
1995	378.7	380.8	498.6	369.4	1628.5
1996	387.8	389.8	498.0	390.7	1666.3
1997	422.7	425	570	402.9	1780
1998	375	370	480	375	1600

<b>EARNINGS PER SHARE *</b>					
Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1994	.35	.44	1.46	.16	2.41
1995	.36	.48	1.46	0.22	2.08
1996	.44	.50	1.58	.09	2.61
1997	.35	.55	1.85	.10	2.85
1998	.30	.50	1.55	.10	2.45

<b>QUARTERLY DIVIDENDS PAID **</b>					
Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1993	.425	.425	.425	.425	1.70
1994	.44	.44	.44	.44	1.78
1995	.455	.455	.455	.455	1.82
1996	.47	.47	.47	.47	1.88
1997	.47	.47	.47	.47	1.88

1181.1	1202.7	1209.4	1256.1	1319.7	1411.8	1482.3	1548.6	1628.5	1666.3	1760	1600	Revenue (\$mil)	1700
86.7	84.2	90.1	76	94.7	107.3	118.2	125.0	112.3	141.5	145	130	Net Profit (\$mil)	135
33.8%	24.9%	26.7%	28.1%	18.5%	9.9%	22.8%	30.3%	37.2%	38.3%	38.0%	38.0%	Income Tax Rate	38.0%
20.2%	27.2%	11.6%	11.1%	9.5%	7.3%	5.5%	6.0%	4.2%	1.6%	1.0%	1.0%	APUDC % to Net Profit	1.0%
47.9%	50.3%	52.3%	54.8%	53.8%	50.7%	53.7%	50.1%	49.1%	46.1%	46.0%	43.0%	Long-Term Debt Ratio	38.0%
42.2%	38.2%	35.5%	34.1%	35.7%	39.0%	37.0%	40.4%	41.8%	44.5%	46.5%	48.0%	Common Equity Ratio	54.0%
1718.9	1922.0	1814.7	1966	2111.4	2152.4	2368.0	2269.4	2364.7	2296.5	2280	2270	Total Capital (\$mil)	2200
2108.0	2275.3	2399.5	2529.1	2611.0	2720.0	2844.6	2930.0	2955.6	2956.6	2860	2770	Net Plant (\$mil)	2475
7.1%	6.5%	7.5%	6.4%	7.1%	7.5%	7.0%	7.5%	7.0%	8.2%	8.5%	8.0%	% Earned Total Cap't	6.0%
9.7%	9.8%	10.4%	8.9%	9.7%	10.1%	10.8%	11.0%	9.3%	11.4%	11.5%	10.5%	% Earned Net Worth	10.0%
10.1%	9.5%	11.2%	9.2%	10.2%	10.8%	11.7%	11.9%	9.8%	12.3%	12.0%	11.0%	% Earned Com Equity E	10.5%
.8%	2%	3%	5%	2.0%	2.5%	2.9%	3.2%	1.2%	3.5%	3.5%	2.5%	% Retained to Com Eq	3.0%
93%	96%	94%	96%	84%	80%	78%	76%	89%	75%	73%	75%	% All Div'ds to Net Prof	75%

**BUSINESS:** Boston Edison Company supplies electricity to an area of approximately 590 square miles in eastern Massachusetts, encompassing Boston and 39 surrounding towns and cities. Territory has a population of about 1.5 million; company serves approximately 658,000 customers. Discontinued steam service in '88. Revenue breakdown: '98 residential, 27% commercial, 50% industrial, 9% other, 14% generating sources, '96 nuclear, 30% gas, 19% oil, 9% purchased, 42%. Fuel costs: 33% of revenues, '96 reported deprec. rate: 3.3%. Est'd plant age: 8 years. Has 3,400 employees, 35,600 stockholders. Chairman, President & C.E.O., Thomas J. May, Inc., MA. Address: 800 Boylston Street, Boston, MA 02199. Tel.: 617-424-2000. Internet: http://www.bostonedison.com

**Boston Edison is close to filing a regulatory settlement.** The agreement with the state attorney general still hasn't been signed, but we expect a filing with the Massachusetts Department of Public Utilities (DPU) later this month.

**The settlement would provide a transition to competition...** Boston Edison would reduce its rate 10% at the start of 1998, or whenever customers get to choose their electricity supplier. It would recover stranded investment through an access charge on customer bills. The utility would divest its fossil generation. The return on equity would be set at 8% initially, but it probably would be 1.25%-1.5% higher by the time customer choice begins, because Boston Edison would get credit for mitigating some stranded investment. The distribution operation would remain regulated, with an ROE cap of 12.5%. The DPU, which has approved a similar settlement for another utility, might issue an order by the end of the third quarter.

**... but it would hurt earnings.** Despite the fact that the utility would recoup all of its stranded investment, the effects of the 10% rate cut and the over allowed ROE

probably would result in an earnings decline. We estimate that 1998 profits would fall about 5%-10%, to \$2.40-\$2.50 a share. Boston Edison wants to form a holding company. It has received the go-ahead from shareholders, and assuming that the DPU approves, the new structure could be in place by yearend. This would enable the company to separate its non-utility ventures (partnerships with gas and telecommunications providers) from its regulated utility operations. **Finances are improving.** The fixed charge coverage is only slightly below the industry average, and the common equity ratio has increased significantly since the early 1990s. We have raised the company's Financial Strength rating from B to B+. Although this stock offers an above-average yield, we think better selections are available elsewhere. The dividend appears secure, but unless Boston Edison's nonutility ventures increase the company's earnings materially, we project no dividend hike over the 3- to 5-year period. Also, the ultimate effects of regulatory restructuring are still uncertain.

*Paul E. Debbas, CFA*  
 June 13, 1997

(A) Excl. nonrecurring gain (loss): '89, (\$2.78); '90, 41c. Incl. restructuring charge: '95, 44c. Next earnings report due late July. (B) Next div'd meeting about July 26. Goes as about July 8. Approx. div'd payment dates: 1st of Feb., May, Aug., Nov. B Div'd reinvestment plan available. (C) Incl. deferred charges in '96: \$241.7 mil., \$4.96/sh, (D) in millions, ac for split. (E) Rate base: Net original cost. Rate allowed on common equity in '95: 11.75%; earned on avg. com. eq.: '96: 12.4%. Regulatory Climate: Average.

Company's Financial Strength 9-  
 Stock's Price Stability 95  
 Price Growth Persistence 80  
 Earnings Predictability 80

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ROCHESTER G. & E. NYSE-RGS										RECENT PRICE	20	P/E RATIO	8.7	(Trading: 8.8 Median: 11.0)	RELATIVE P/E RATIO	0.53	DIV YLD	9.0%	9/60/0	VALUE LINE	191	
<b>TIMELINESS</b> (Relates Price Perform.) since Nov 12 Mos. <b>3</b> Average <b>SAFETY</b> (Scale: 1 Highest to 5 Lowest) <b>3</b> Average <b>BETA</b> .55 (1.00 = Market)										High: 29.9 25.9 18.3 22.1 21.8 23.9 25.3 29.8 28.4 24.1 23.8 20.4 Low: 21.3 14.3 14.8 17.0 16.9 17.8 21.0 24.1 19.9 20.0 17.9 18.0										Target Price Range 2000   2001   2002		
<b>2000-02 PROJECTIONS</b> Price Gain Ann'l Total High 30 (-50%) 17% Low 18 (-10%) 6%										1.01% Dividend on an divided by Interest Rate Relative Price Strength Options: None										50 40 32 24 20 16 12 10 8 6 4 2 0		
<b>Insider Decisions</b> J A S O N D J F M to buy 0 0 0 0 1 0 1 0 0 0 to sell 0 0 0 0 0 0 0 0 0 0										<b>Institutional Decisions</b> Buy 40 40 32 Sell 34 38 50 Net Buy 6 2 18										Percent of Shares 6.0 Traded 2.0		
<b>CAPITAL STRUCTURE as of 3/31/97</b> Total Debt \$667.0 mil. Due in 5 Yrs \$110.2 mil LT Debt \$647.0 mil. LT Interest \$47.4 mil. (LT Interest @ 6.4%) Leases, Uncapitalized Annual rentals \$5.9 mil. Pension Liability None Pfd Stock \$112.0 mil. Pfd Div'd \$6.8 mil 670,000 shs. 4.0% to 7.5% cum. (\$100 par), call- able at \$101 to \$105; 550,000 shs. 6.60%-7.65% cum., subject to mandatory redemption beginning 9/1/97. Excl. pfd. stock due within one year. Common Stock 38,851,466 shs. as of 6/30/97										731.5 774.0 845.7 830.9 853.3 886.5 948.0 1000.8 1016.3 1054.0 1080.1 1085.1 80.2 78.1 72.8 59.9 64.6 70.4 78.8 74.4 71.9 97.5 85.0 95.0 32.4% 33.9% 32.5% 34.8% 33.9% 35.9% 33.5% 37.7% 40.7% 40.4% 38.5% 46.5% 9.6% 5.0% 5.9% 9.0% 5.5% 3.3% 2.4% 3.2% 4.8% 2.2% 1.0% 1.0% 57.3% 55.3% 53.4% 51.6% 48.4% 45.8% 47.2% 45.9% 44.9% 41.9% 40.0% 40.0% 34.7% 38.0% 39.9% 41.4% 42.5% 45.8% 45.9% 46.5% 47.5% 50.9% 54.5% 55.0% 1474.8 1434.6 1433.2 1397.5 1390.2 1438.4 1583.9 1602.3 1596.1 1545.5 1475.1 1495.1 1474.8 1510.1 1548.3 1580.0 1604.8 1629.3 1668.5 1686.9 1671.0 1680.4 1625.1 1615.1 7.9% 7.8% 7.5% 6.6% 6.9% 7.0% 6.7% 6.4% 6.2% 7.9% 8.0% 7.5% 12.7% 11.9% 10.9% 8.9% 9.0% 9.0% 9.4% 8.8% 8.2% 10.9% 10.5% 10.5% 14.1% 12.6% 11.7% 9.3% 9.8% 9.4% 9.8% 9.0% 8.5% 11.4% 11.0% 11.0% 3.3% 4.2% 3.6% 5% 1.2% 1.1% 1.4% 2% NMF 2.6% 2.5% 2.5% 79% 70% 72% 91% 88% 90% 87% 88% 105% 79% 80% 80%										Revenues per sh 31.75 Cash Flow per sh 7.00 Earnings per sh 2.25 Div'd Dec'd per sh 1.80 Cap'l Spending per sh 2.75 Book Value per sh 22.50 Common Shs Outst'g 34.50 Avg Ann'l P/E Ratio 10.5 Relative P/E Ratio .75 Avg Ann'l Div'd Yield 7.8%		
<b>ELECTRIC OPERATING STATISTICS</b> 1998 1995 1996 % Change Fuel Sales (MM) -2 -2.8 -3 Avg Indus. Use (MM) 1358 1451 1504 Avg Indus. Rev. per (MM) 8.08 8.01 7.63 Capacity of Plant (MW) 1600 1619 1617 Fuel Used, Surplus (MM) 1374 1425 1305 Average Load Factor (%) 58.8 57.8 61.9 % Change Customers (thous) +8 -8 -2										<b>BUSINESS:</b> Rochester Gas and Electric Corporation produces and distributes electricity (67% of revenues) and distributes gas (33%) in parts of nine counties centering around Rochester, New York. Service area population: about 1,000,000. Electric (gas) revenue breakdown: 96: residential, 38% (73%); commercial, 31% (15%); industrial, 22% (2%); other utilities, 2%; other, 9% (10%). Generation sources: 96: nuclear, 50%; coal, 18%; hydro & other, 3%; purchased, 29%. Fuel costs: 27% of revenues. 96 reported depreciation rate: 3.0%. Estimated plant age: 13 years. Has 1,900 employees, 33,675 stockholders. Chairman & C.E.O.: Roger W. Kobler. President & C.O.O.: Thomas S. Richards, Inc. NY. Address: 89 East Avenue, Rochester, NY 14649-0001. Tel: 716-546-2700.										1096 85.0 48.5% 1.0% 42.5% 53.5% 1450 7.5% 10.0% 10.5% 2.5% 79%		
<b>ANNUAL RATES</b> Past 5 Yrs. Est'd '94-'96 of change (per sh) Revenues .5% 3.0% Cash Flow .5% -1.0% 6.5% Earnings -6.0% 5% 2.5% Dividends -2.0% 2.5% Nil Book Value -2.0% 1.5% 2.0%										<b>Rochester Gas and Electric has reached a regulatory settlement with the staff of the New York State Public Service Commission and some intervenor groups. Under the agreement, through mid-2002 the utility's electric rates would be lowered by a total of \$72.1 million over and above rate reductions that were specified in a previous settlement. Customers would gradually get the right to choose their electricity supplier, beginning in mid-1998, with all ratepayers having their choice by mid-2002. RG&amp;E would have an opportunity to recover its stranded costs, but not a guarantee of recovery. If the return on equity exceeds 11.8% over the life of the agreement, half of the excess would be used to reduce regulatory assets or stranded costs. The commission must still approve the settlement; its decision is expected by the end of the third quarter.</b>										effects of lower rates would be minimal in the short run, but they would reduce share earnings by \$0.40 in 2001. We assume in our projections that the settlement is adopted, and that the company will be able to offset most of the effects of the rate cuts through modest sales growth, cost control, and share repurchases. A dividend reduction isn't necessarily imminent, but it can't be ruled out either. If RG&E can reach our earnings estimates of \$2.30 a share in 1997 and 1998, then the payout ratio will be 80%. That's high, but it isn't high enough to make the dividend unsustainable at the current level. Still, because RG&E's dividend policy states that increased competition and uncertainty will require consideration... of a dividend payout ratio that is lower over time, a dividend cut is possible. This stock is unsuitable for most utility investors. If the dividend holds at the current level, then speculative accounts should benefit from the high yield. But other investors should avoid these shares due to the uncertainty surrounding the dividend and the effects of competition.		
<b>QUARTERLY REVENUES (\$ mil.)</b> Cal-ender Mar.31 Jun.30 Sep.30 Dec.31 Full Year 1994 310.1 217.1 229.9 243.7 1000.8 1995 281.1 219.6 245.1 270.5 1016.3 1996 309.2 235.6 234.8 274.4 1054.0 1997 314.8 240 250 275.2 1080 1998 320 240 250 275 1085										<b>QUARTERLY EARNINGS PER SHARE *</b> Cal-ender Mar.31 Jun.30 Sep.30 Dec.31 Full Year 1994 .37 .20 .08 .63 1.79 1995 .75 .34 .65 0.05 1.69 1996 1.05 25 .49 .52 2.32 1997 1.02 .25 .55 .48 2.30 1998 1.00 .25 .55 .50 2.30										1096 85.0 48.5% 1.0% 42.5% 53.5% 1450 7.5% 10.0% 10.5% 2.5% 79%		
<b>QUARTERLY DIVIDENDS PAID **</b> Cal-ender Mar.31 Jun.30 Sep.30 Dec.31 Full Year 1993 .43 .43 .43 .43 1.72 1994 .44 .44 .44 .44 1.76 1995 .45 .45 .45 .45 1.80 1996 .45 .45 .45 .45 1.80										<b>The rate reductions are necessary, but RG&amp;E must find a way to offset their effects on earnings. The utility's rates are high, and although it hasn't lost any electric customers, it has had to forgo some revenue through discounted prices and avoidance of performance awards. The</b>										1096 85.0 48.5% 1.0% 42.5% 53.5% 1450 7.5% 10.0% 10.5% 2.5% 79%		

(A) Excludes nonrecurring losses: '85, 27c; '87, \$8.07; '89, 5c; '91, 21c. Next earnings report due late July. '96 earnings don't add to total due to rounding. (B) Next div'd meeting about June 17. Goes ex about June 26. Approximate div'd payment dates: 25th of Jan., Apr., July, Oct. a Div'd reinvestment plan available. (C) Incl. deferred debts. In '96: \$450.6 mil., \$11.80/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in '93: 11.5%; earned on average cum. eq.: '96: 11.4%. Regulatory Climate: Below Average. Company's Financial Strength B+ Stock's Price Stability 100 Price Growth Persistence 35 Earnings Predictability 70 To subscribe call 1-800-833-0045.

## Duquesne Light Company Comparable Group Criteria

<u>Company</u>	<u>Total Capitalization</u> ---(\$ Million)---	<u>Revenue from Electricity</u> ---(Percent)---
	(a)	(b)
Atlantic Energy, Inc.	\$ 1,800.3	100 %
Baltimore Gas & Electric Co.	5,960.4	70
Carolina Power & Light Co.	5,359.9	100
Dominion Resources, Inc.	10,476.0	91
Duke Power Co.	9,110.8	92
GPU, Inc.	6,741.7	100
IES Industries	1,365.9	59
PECO Energy Co.	9,308.5	90
PP&L Resources, Inc.	6,179.0	100 <sup>1</sup>
Public Service Enterprise Group	10,527.0	65
Average	\$ 6,682.9	86.7 %

<sup>1</sup> Based on 1994 data.

Source: *Utility Compustat II*, Standard & Poor's  
Compustat Services, Inc.

**Duquesne Light Company  
Annual DCF, Comparable Group of Companies**

Company	Dividends Paid				Dividend Sum (D <sub>0</sub> )	Average Adjusted Price (P <sub>0</sub> ) <sup>1</sup>	B*R+S*V Growth <sup>2</sup>	EPS Growth Estimate <sup>3</sup>	Average Growth (g)	DCF Cost of Equity <sup>4</sup>
	Q2 '96	Q3 '96	Q4 '96	Q1 '97						
	(Dollars)						(Percent)			
	(a)	(b)	(c)	(d)	[(a)+(b)+(c)+(d)] (e)	(f)	(g)	(h)	(i)	(j)
Atlantic Energy, Inc.	\$ 0.39	\$ 0.39	\$ 0.39	\$ 0.39	\$ 1.54	\$ 17.03	3.50 %	8.06 %	5.78 %	15.85 %
Baltimore Gas & Electric Co.	0.39	0.40	0.40	0.40	1.59	26.42	5.81	9.03	7.42	14.22
Carolina Power & Light Co.	0.46	0.46	0.47	0.47	1.85	35.58	2.61	3.11	2.86	8.49
Dominion Resources, Inc.	0.65	0.65	0.65	0.65	2.58	37.29	3.24	5.72	4.48	12.09
Duke Power Co.	0.51	0.53	0.53	0.53	2.10	46.06	4.94	3.49	4.22	9.22
GPU, Inc.	0.49	0.49	0.49	0.49	1.94	33.16	5.43	8.71	7.07	13.66
IES Industries	0.53	0.53	0.53	0.53	2.10	30.03	2.82	3.73	3.27	10.88
PECO Energy Co.	0.44	0.44	0.45	0.45	1.77	22.70	3.40	2.63	3.01	11.47
PP&L Resources, Inc.	0.42	0.42	0.42	0.42	1.67	21.65	2.87	0.48	1.68	9.94
Public Service Enterprise Group	0.54	0.54	0.54	0.54	2.16	26.34	2.91	2.96	2.93	11.82
	\$ 0.48	\$ 0.48	\$ 0.48	\$ 0.48	\$ 1.93	\$ 29.62	3.75 %	4.79 %	4.27 %	11.76 %

<sup>1</sup> Equals the June 16, 1997 closing stock price adjusted for the ex-dividend date.

<sup>2</sup> B\*R+S\*V uses a five year average of S, multiplied by current V.

<sup>3</sup> Calculated using 1996 and five year projected data.

<sup>4</sup> Annual DCF equals  $[D_0 * (1+g) / P_0 / (1-5.00\%+g)]$ .

Sources: *Utility Compustat II*, Standard & Poor's Compustat Services, Inc.  
*The Value Line, Investment Survey*, Edition 1, June 13, 1997, Edition 5,  
April 11, 1997 and Edition 11, May 23, 1997.  
*Factsset Security Price History Report*.

**Duquesne Light Company**  
**Average Adjusted Stock Price**  
**Comparable Group of Companies**

<u>Company</u>	<u>Average Stock Price</u> <sup>1</sup>	<u>Last Dividend Paid</u>	<u>Average Adjusted Price</u>
	(Dollars)		
	(a)	(b)	[(a)-(b)/2] (c)
Atlantic Energy, Inc.	\$ 17.22	\$ 0.39	\$ 17.03
Baltimore Gas & Electric Co.	26.62	0.40	26.42
Carolina Power & Light Co.	35.82	0.47	35.58
Dominion Resources, Inc.	37.61	0.65	37.29
Duke Power Co.	46.32	0.53	46.06
GPU, Inc.	33.40	0.49	33.16
IES Industries	30.29	0.53	30.03
PECO Energy Co.	22.92	0.45	22.70
PP&L Resources, Inc.	21.86	0.42	21.65
Public Service Enterprise Group	26.61	0.54	26.34
			\$ 29.62

<sup>1</sup> Average of weekly (Friday) close prices from July 17, 1996 to July 11, 1997.

Sources: *The Value Line Investment Survey*, Edition 1, June 13, 1997; Edition 5, April 11, 1997 and Edition 11, May 23, 1997.

*Factset Security Price History Report.*

**Duquesne Light Company**  
**Sustainable Growth, Comparable Group of Companies**

Company	R	D <sub>e</sub>	V <sub>e</sub>	V		R <sub>av</sub>	Average		Average	
	Estimated	Estimated	Estimated	Book Equity		Return on	Equity		S*V	
	Return on	Dividend <sup>2</sup>	Book Equity <sup>2</sup>	Per Share		Average	B <sup>4</sup>	B*R <sup>5</sup>	S*V <sup>6</sup>	B*R+S*V
	Common Equity <sup>1</sup>			1996	1995	Equity <sup>3</sup>				
	---(Percent)---		---(Dollars)---					---(Percent)---		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Atlantic Energy, Inc.	9.5 %	\$ 1.00	\$ 17.00	\$ 15.00	\$ 15.48	9.35 %	37.09 %	3.47 %	0.03 %	3.50 %
Baltimore Gas & Electric Co.	12.0	1.78	24.15	19.35	19.06	12.09	39.03	4.72	1.09	5.81
Carolina Power & Light Co.	13.0	2.14	22.20	17.77	16.93	13.32	27.60	3.68	-1.06	2.61
Dominion Resources, Inc.	10.5	2.58	30.50	27.17	26.88	10.56	19.87	2.10	1.14	3.24
Duke Power Co.	13.0	2.50	31.30	24.25	23.36	13.24	39.69	5.26	-0.31	4.94
GPU, Inc.	11.5	2.20	32.50	25.27	24.70	11.63	41.80	4.86	0.57	5.43
HES Industries	10.5	2.10	22.75	20.84	20.75	10.52	12.28	1.29	1.53	2.82
PECO Energy Co.	11.0	1.84	23.70	20.87	20.39	11.13	30.23	3.36	0.04	3.40
PP&L Resources, Inc.	11.0	1.67	19.00	16.88	16.29	11.19	21.47	2.40	0.47	2.87
Public Service Enterprise Group	11.5	2.22	25.25	22.33	22.25	11.52	23.68	2.73	0.18	2.91
	11.4 %	\$ 2.00	\$ 24.84	\$ 20.97	\$ 20.61	11.45 %	29.27 %	3.39 %	0.37 %	3.75 %

<sup>1</sup> 2000-2002 estimate.

<sup>2</sup> 2000-2002 estimated per share dividends and book value.

<sup>3</sup>  $R_{av} = (2 * R * V_{96}) / (V_{96} + V_{95})$ .

<sup>4</sup>  $B = 1 - (D_e / (R_{av} * V_e))$ .

<sup>5</sup>  $B * R = B * R_{av} = (R_{av} - D_e / V_e)$ .

<sup>6</sup> S\*V equals five year average of S, multiplied by current V, where S = annual growth rate of common shares outstanding and V = fraction of new funds provided that accrues to original shareholders.

Sources: *Utility Compustat II*, Standard & Poor's Compustat Services, Inc.  
*The Value Line, Investment Survey*, Edition 1, June 13, 1997,  
Edition 5, April 11, 1997 and Edition 11, May 23, 1997.

**Duquesne Light Company**  
**S and V Data, Comparable Group of Companies**

Company	S						Average S <sup>1</sup>	V <sup>2</sup>	S*V
	1992	1993	1994	1995	1996	Average S <sup>1</sup>			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(f)*(g)  (h)	
Atlantic Energy, Inc.	0.0203	0.0194	0.0073	-0.0334	0.0000	0.0027	0.1011	0.0003	
Baltimore Gas & Electric Co.	0.1570	0.0215	0.0123	0.0001	0.0013	0.0384	0.2837	0.0109	
Carolina Power & Light Co.	0.0000	0.0000	-0.0414	-0.0486	-0.0107	-0.0201	0.5274	-0.0106	
Dominion Resources, Inc.	0.0472	0.0452	0.0400	0.0335	0.0340	0.0400	0.2853	0.0114	
Duke Power Co.	0.0000	0.0000	0.0000	0.0000	-0.0316	-0.0063	0.4958	-0.0031	
GPU, Inc.	0.0000	0.0514	0.0000	0.0582	0.0000	0.0219	0.2605	0.0057	
IES Industries	0.0220	0.1569	0.0169	0.0251	0.0216	0.0485	0.3148	0.0153	
PECO Energy Co.	0.0030	0.0069	0.0005	0.0034	0.0024	0.0033	0.1105	0.0004	
PP&L Resources, Inc.	0.0025	0.0027	0.0273	0.0312	0.0282	0.0184	0.2548	0.0047	
Public Service Enterprise Group	0.0496	0.0543	0.0053	0.0000	-0.0536	0.0111	0.1639	0.0018	
						0.0158	0.2798	0.0037	

<sup>1</sup> Average of five most recent years.

<sup>2</sup>  $V = (1 - (1995 \text{ Book Value per Share} / \text{Average Stock Price}))$ .

Sources: *Utility Compustat II*, Standard & Poor's Compustat Services, Inc.  
*Factset Security Price History Report*.

## Duquesne Light Company EPS Growth Estimate

Company	EPS		
	1996	2000-2002 Estimated	Estimated Growth <sup>1</sup>
	------(Dollars)-----		--(Percent)--
	(a)	(b)	(c)
Atlantic Energy, Inc.	\$ 1.12	\$ 1.65	8.06 %
Baltimore Gas & Electric Co.	1.85	2.85	9.03
Carolina Power & Light Co.	2.66	3.10	3.11
Dominion Resources, Inc.	2.65	3.50	5.72
Duke Power Co.	3.37	4.00	3.49
GPU, Inc.	2.47	3.75	8.71
IES Industries	2.04	2.45	3.73
PECO Energy Co.	2.24	2.55	2.63
PP&L Resources, Inc.	2.05	2.10	0.48
Public Service Enterprise Group	2.42	2.80	2.96
	\$ 2.29	\$ 2.88	4.79 %

<sup>1</sup> Growth equals  $[(2000-2002 \text{ estimate}/1996 \text{ actual})^{0.20}]-1$ .

Sources: *Utility Compustat II*, Standard & Poor's Compustat Services, Inc.  
*The Value Line, Investment Survey*, Edition 1, June 13, 1997;  
Edition 5, April 11, 1997 and Edition 11, May 23, 1997.

Reporting NERA's work on public policy,  
management and litigation economics

## FOUR COMMON ERRORS IN APPLYING THE DCF MODEL IN UTILITY RATE CASES

By

Jeff D. Makholm  
Vice President

Donald O. Sander  
Analyst

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The DCF model, properly used, is an objective tool that can be used to obtain objective results. Despite the questions raised by its detractors, the DCF model remains an attractive and easily understood method for determining the fair rate of return on equity.

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Over the past two decades, the "Discounted Cash Flow" model (DCF) has emerged as the primary tool for determining the fair rate of return on equity for utilities in the United States. It is referenced in the documents of most regulatory commissions and in their decisions. Despite this apparent acceptance, the use of the DCF model and its results remain controversial.

Much of the disagreement in utility rate cases involves judgmental questions regarding the use of *empirical* data. This sort of disagreement is not surprising. Disagreement over the *theoretical* construction of the DCF model, however, is largely unnecessary. The DCF model, properly used, is an objective tool that can be used to obtain objective results. Despite the questions raised by its detractors, the DCF model remains an attractive and easily understood method for determining the fair rate of return on equity. In short, it is a good tool that is often used poorly.

The appeal of the DCF model is its relative simplicity, though that simplicity leads to the kinds of application errors that we will examine here. The way that utilities pay dividends and issue new stock requires adjustments to the basic model in order for the DCF model to be used correctly in rate of return proceedings.

After a brief description of the basic DCF model, we will describe what we observe to be four of the most common errors in applying the model that needlessly contribute to rate of return discord. These errors are the "Ex-Dividend Date" Error, the "Current Dividend Yield" Error, the "Sustainable Growth" Error, and the "Flotation Cost" Error.

### The Basic DCF Model

The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models that was first

published in complete form in 1962.<sup>1</sup> According to the model, investors view a company as a money machine that produces dividends on a quarterly basis. At the end of each quarter, some of the earnings that have accrued over that quarter are retained by the company to create future earnings. The rest are paid out as dividends and the process begins anew. To investors, the value of a share of stock is the dividends it will pay out during the period the investor holds the stock, plus any capital appreciation earned at the time the stock is sold. The DCF model estimates the "cost of equity" by computing the discount rate that equates a stock's current market price with the present value of all future expected dividends and capital gains. Stated simply, the DCF methodology shows that a firm's cost of equity is equal to its dividend yield (dividend per share divided by stock price) plus its expected long-term dividend growth rate. This equation, known in the financial literature as the "periodic" DCF model, can be found in Appendix A.

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**To investors, the value of a share of stock is the dividends it will pay out during the period the investor holds the stock, plus any capital appreciation earned at the time the stock is sold.**

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Like most theoretical models, the DCF employs assumptions, not all of which hold true in the real world. While these theoretical abstractions from the real world are almost always necessary in practice, it is important to distinguish between those assumptions that do not bias the calculated result over time and those that *do*. The latter type, which are the source of the four most common DCF errors we observe and describe here, are easy to remedy.

### The "Ex-Dividend" Date Error

The DCF model requires the measurement of a current stock price as one of its inputs. It assumes that the stock price will be observed *on the "ex-dividend" date*. The ex-dividend date is the date upon which the right to the next dividend (to be paid out a few days hence) no longer accompanies a share of stock. In other words, an investor who purchases a share of stock on the ex-dividend date will have to wait a full quarter (90 days) before receiving a dividend payment.

If the stock price is measured on any other date, or if an average stock price is used in the DCF equation, the resulting cost of equity calculation will be too low. To understand why this is so, consider again the money machine analogy. At the beginning of a new quarter—that is,

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<sup>1</sup> See: Gordon, Myron J., *The Investment, Financing and Valuation of the Corporation*, Richard D. Irwin Inc., 1962.

*immediately* after the previous dividend was paid—a company begins to accrue new earnings (and therefore potential dividends) and its market value increases. The DCF model assumes that these potential dividends accrue evenly throughout the quarter. On the day it pays out dividends, we would expect the market value of the firm (i.e., its stock price) to drop. In fact, stock prices do indeed drop by an amount approximately equal to the quarterly dividend on the ex-dividend date.<sup>2</sup>

According to the basic DCF model, the stock price should be measured when the next dividend is one *full* quarter away, on the ex-dividend date. If the stock price is measured a week after the ex-dividend date, then seven days of potential dividends will have accrued and the observed stock price will be slightly higher (by approximately the amount of the accrued portion of the quarterly dividend). The basic DCF model *misinterprets this slightly higher stock price not* merely as a soon-to-occur dividend payment date, but rather as a lower discount rate—i.e., a lower cost of equity capital. This downward bias, while different in each case, can mean roughly \$1 to \$2 million *per year* in equity return for an average electric utility, depending on the equity component of rate base.<sup>3</sup>

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... it is important to distinguish between those assumptions that do not bias the calculated result over time and those that do.

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This error is easy to remedy by referring to the ex-dividend date of the company in question. The remedy can take one of three forms. Either: (1) use the traditional DCF model but measure stock prices only on the ex-dividend date; (2) alter the traditional DCF model to account for the nearer dividend payment at the time the price is measured; or (3) use the traditional DCF model at any date or average of dates but remove from the observed stock price the effect of nearer dividend payments.

We consider the third option the easiest and most applicable to utility rate cases, where the need for current information makes it undesirable to wait until the ex-dividend date to measure the stock price. This method makes use of the fact that the stock price accrues the next anticipated dividend in

<sup>2</sup> A discussion of the importance of the ex-dividend date appears in most financial texts. As an example, see: E.F. Brigham, *Financial Management Theory and Practice, 3rd Edition*, 1982, page 687.

<sup>3</sup> The ex-dividend date adjustment has recently been adopted as a regular component of the fair rate of return in proceedings before the New York Public Service Commission. It was first instituted in Opinion 90-29 (Brooklyn Union Gas Company), where it was proposed by Dr. Makholm.

a generally linear fashion, meaning that halfway between ex-dividend dates, approximately half of the next anticipated dividend is embedded in the observed stock price. It is possible, therefore, to use a stock price observed on any date if that stock price is reduced by the amount of the next dividend that has already been capitalized into the stock price. The third option removes that proportion of the next expected dividend from the stock price. This modification to the DCF model, which removes the effect of accrued dividends, can be found in Appendix B.

### The Current Dividend Yield Error

Many rate of return analysts (including those at the FERC who employ the agency's "generic" rate of return formula) use a "hybrid" of the traditional DCF model that causes a mathematical understatement of the cost of equity, on average.<sup>4</sup> This error is due to the incorrect estimation of the next period's dividend yield in the traditional DCF model.

The correct way to calculate the expected dividend payments over the next year is to observe the *past* period's dividend payments and to multiply them by the expected long-term dividend growth rate. However, many analysts incorrectly use the "current" dividend yield published in the trade press (the latest quarterly dividend multiplied by four and divided by the current price) and multiply it by *half* the expected growth rate to get next period's dividend. The reasoning behind this hybrid DCF model is that if the "past" dividend yield is simply the sum of the four previous dividends divided by the stock price and the "future" dividend yield is the same period's dividend multiplied by one plus the growth rate, then the "current" dividend yield must be halfway between the two (i.e., the current yield and half of the growth rate). This is incorrect and leads to an understatement of the cost of equity capital, on average.

The following example shows this<sup>5</sup>: A hypothetical company has the following characteristics at its ex-dividend date:

Current price	=	\$20
Expected dividend growth	=	5 percent
Latest quarterly dividend	=	\$0.40

<sup>4</sup> We should note that, just recently, the FERC discontinued its practice of relying on a generic rate of return calculation.

<sup>5</sup> A more rigorous mathematical proof of Dr. Makhholm's shows that the dividend yield understatement is equal to  $g(1/2) D_{t-1}$ , or one-half of the last dividend multiplied by the rate of growth.

The *current* dividend yield in this scenario is 8.0 percent  $[(4 \times .40)/20]$ . Using the current dividend yield approach, one would then increase this figure by one-half of the expected growth rate to get the *next* period's dividend yield of 8.2 percent  $(8.0 \times [1 + (.05/2)])$

We expect, however, that sometime during the next year the \$0.40 dividend will increase by the 5 percent expected growth rate to \$0.42  $(.40 \times 1.05)$ . This could occur during any one of the four quarterly dividend periods. The following table shows what happens to the expected dividend yield under the four alternate scenarios:

**Table 1: Use of Current Yield Understates Expected Dividend Yield**

Dividend of \$0.40 increases to \$0.42:	Expected Dividend	Expected Dividend Yield	Current Dividend Yield	Difference
1st quarter hence	\$1.68	8.4%	8.2%	0.2%
2nd quarter hence	\$1.66	8.3%	8.2%	0.1%
3rd quarter hence	\$1.64	8.2%	8.2%	----
4th quarter hence	\$1.62	8.1%	8.2%	-0.1%
Average		8.25%	8.2%	0.05%

The example shown in Table 1 demonstrates that, on average, the "current dividend yield" method understates the true expected dividend yield by .05 percent. While this expected error seems small, it is an assured bias in the calculated result and is easily avoided by using the last period's dividends multiplied by the expected dividend growth rate. In addition, this "small" understatement can cost the average utility over \$1 million per year in equity return.

### The Sustainable Growth Error

Since the DCF dividend growth rate cannot be observed directly because it exists in the minds of investors, one of the most popular methods for estimating it is the "sustainable growth" or "plowback" method. This method produces a forward-looking sustainable growth rate by multiplying the fraction of earnings a company expects to retain by the expected return on book equity. This is a valid method of

estimating future dividend growth since growth in the dividends can only occur if a portion of the expected equity return is reinvested instead of being paid out as dividends.

The basic DCF model assumes that the only source of equity financing is the retention of earnings. In practice, however, the issuance and sale of new common stock at prices *in excess of book value* can also be a source of earnings growth for existing shareholders. If shares are sold when the price is above book value, a portion of the funds go to current shareholders as share appreciation.

The failure to recognize this second source of growth most often results in a significant understatement of the investors' expected growth rate. That is, if investors expect this additional growth and that expectation is reflected in what they pay for a share of stock, and if a rate of return analyst fails to take this source of growth into account when applying the retention growth formula, then the calculated cost of capital is too low.

It is, of course, possible for utilities to issue new shares at prices either *above or below* book value. In practice, however, it is considerably more likely that new shares will be issued above book value rather than below. There are three reasons for this. *First*, there is an obvious reluctance on the part of utility managements to dilute share prices. They will—and do—try to avoid equity financings when stock prices are low by instead issuing debt. *Second*, a considerable amount of new utility equity takes the form of employee stock plans. When stock prices are high (that is, above book value), utilities issue *new* shares to fund these plans. When stock prices are below book value, utilities can—and do—fund these plans by purchasing *existing* shares in the market, thereby avoiding dilution. *Third*, historical stock prices reveal many more years of prices above book value than below.

If stocks are sold at a price that exceeds book value and if this is not reflected in the retention growth rate formula, then the cost of equity will be understated, on average. The size of this understatement will depend on the particular case involved but on average is likely to be in the range of \$3 to \$5 million *per year* of equity return.<sup>6</sup>

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**... the issuance and sale of new common stock at prices *in excess of book value* can also be a source of earnings growth for existing shareholders.**

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<sup>6</sup> This assumes that the retention growth rate is used exclusively in the DCF model.

The expanded growth rate, which incorporates growth from equity issuances at prices above book value, reduces to the standard version either when the company does not regularly sell new stock or when the new stock is sold at a price that equals book value. The formula for this growth rate can be found in Appendix C.<sup>7</sup>

### The Flotation Cost Error

The issuance (flotation) of common equity involves both direct expenses and underwriting fees. These costs are often measured as a percentage of the total common equity issuance. Because of these issuance costs, the net proceeds of a common equity issuance will *always* be less than the total purchase price of the securities issued. If no adjustment is made in the fair rate of return to reflect these expenses, and if no other provision is made to reimburse the utility for these expenses, the resulting fair rate of return on equity calculations will be too low.<sup>8</sup>

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**Because of . . . issuance costs, the net proceeds of a common equity issuance will *always* be less than the total purchase price of the securities issued.**

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The DCF model can be used for calculating the proper return *on net proceeds* to compensate the utility for its issuance expenses. The only necessary change to the model is to reduce the observed stock price by an amount equal to the flotation cost percentage. This reduction is necessary because the prevailing observed stock price represents the gross proceeds to the investor, not the net proceeds to the utility. The conventional form of the issuance expense adjustment can be found in Appendix D.

This adjustment is applicable to *total* common equity (common stock plus retained earnings), not just the common stock account. Since the cash "paid in" by investors is greater than the net proceeds that the company "takes in," the company must earn a greater return on the smaller net proceeds balance to compensate investors adequately for their expected cost of capital on the "paid in" investment. But the money "paid back" to the investors in any year, the dividend, reflects only a portion of the cost of capital. The

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<sup>7</sup> A positive adjustment to the sustainable growth rate to reflect stock issuances at prices above book values has become a regular component of the fair rate of return before the New York Public Service Commission. It was first instituted in Opinion 90-29 (Brooklyn Union Gas Company), where it was proposed by Dr. Makholm.

<sup>8</sup> A good discussion of the controversy surrounding the issuance and selling expense adjustment can be found in *Utilities Cost of Capital*, R. A. Morin, Public Utilities Reports, Inc, 1984, pp. 98-111, and in a comprehensive article on the subject in *Public Utilities Fortnightly*, May 2, 1985, entitled "Common Equity Flotation Costs and Rate Making," by Brigham, E. F. *et al.*

other portion is retained earnings, the funds used to finance future growth and future dividends. If the retained earnings account does not receive a selling and issuance return adjustment, it will not grow at a rate sufficient to allow for the payments of dividends at investors' expected growth rate in the future.

To understand this relationship better, compare two companies with the same cost of capital and issuance expense percentage. One pays out all its earnings as dividends (i.e., it retains no earnings), while the other pays no dividends (i.e., it retains all earnings). If we applied an issuance expense adjustment only on the "common stock" balance, while ignoring the retained earnings, investors in the company that retains no earnings would receive a greater return than investors in the company that retains all its earnings. This penalizes the second company, whose selling expense percentage was the same, simply because it decided to finance itself through retained earnings rather than by issuing new stock.

### Conclusion

As long as rate base/rate of return regulation is the standard by which electric and gas utilities in the U.S. are regulated, there will be extensive debate regarding the "fair" rate of return. The true cost of equity capital will remain unobservable and a utility's risk will not be measured with scientific precision. The process, however, can be made somewhat less contentious if there is agreement on the proper basic DCF model as well as a proper theoretical treatment for the four problems identified here.

## APPENDIX A

The Basic DCF Model

The following equation, referred to in this paper as the "Basic" DCF model, is known in the financial literature as the "periodic" DCF model:

$$k_e = \frac{D_0(1+g)}{P_0} + g$$

where:

$k_e$  = the cost of equity;

$D_0$  = the previous dividend paid;

$g$  = the dividend growth rate; and

$P_0$  = the stock price.

(1)

## APPENDIX B

The Ex-Dividend Date Adjustment

The following equation adjusts the basic DCF model to account for the ex-dividend date phenomenon:

$$\bar{k}_e = \frac{D_0(1+g)}{\bar{P}_0} + g$$

where:

$\bar{k}_e$  = the cost of equity adjusted for the ex-dividend date;

$D_0$  = the previous dividend paid;

$g$  = the dividend growth rate; and

$\bar{P}_0$  = the observed stock price minus the accrued dividend

$$= P_0 - \left[ \frac{\text{days until next ex-dividend date}}{90} \right] * [\text{next dividend}].$$

(2)

## APPENDIX C

The Expanded Growth Rate Formula That Adjusts  
For The Issuances Of Equity At Prices Above Book Value

The basic DCF sustainable growth rate must be expanded to allow for continuous new equity financing. In the expanded formula, two activities are recognized: (1) investment decisions, which earn the rate of  $R_{av}$ , and (2) stock financing operations, which earn the rate  $S+V$ . The sustainable growth would then be:

$$g = B \cdot R_{av} + S + V$$

where:

- $B$  = the fraction of earnings expected to be retained;
- $R_{av}$  = the expected return on average equity;
- $S$  = the funds raised from the sale of stock as a fraction of existing common equity; and
- $V$  = the fraction of funds raised from the sale of stock that accrues to shareholders at the start of the period.

(3)

The  $S+V$  term is a measure of the effect on current investors' expected dividend growth due to the sale of stock at prices above or below book value.

## APPENDIX D

The Flotation Cost Adjustment

The following formula adjusts the basic DCF model to account for selling and issuance expenses:

$$r = \frac{D_1}{P_0(1-f)} + g$$

where:

- $r$  = the required return adjusted for issuance expenses;
- $D_1$  = the next period's dividend;
- $P_0$  = the stock price;
- $f$  = the flotation cost percentage; and
- $g$  = the dividend growth rate.

(4)

The  $(1-f)$  term represents net common equity proceeds as a percentage of gross common equity proceeds.

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