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Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

DOCKETED
MAR 24 1986

REBUTTAL TESTIMONY OF
JOSEPH F. PAQUETTE, JR.

FINANCIAL IMPACT OF OPPOSING
PARTY RATE PROPOSALS;
ADDITIONAL FINANCINGS
REQUIRED UNDER THE OKA
HYPOTHETICAL LIMERICK
CONSTRUCTION SCHEDULE

February 19, 1986

REBUTTAL TESTIMONY OF JOSEPH F. PAQUETTE, JR.

Q. Mr. Paquette have you previously presented Direct Testimony in this proceeding?

A. Yes. My Direct Testimony was previously admitted into evidence as PECO Statement 3.

Q. Mr. Paquette, what is the purpose of your Rebuttal Testimony?

A. This testimony will first summarize and present an assessment of the financial impact on the Company if the PUC were to grant a rate increase or phase-in plan in this proceeding in accordance with the positions advocated by the various intervenors. Secondly, I will present a summary of the hypothetical changes to our actual historic financing program which would have been required if the Company had attempted to complete Limerick 1 for fuel loading on July 31, 1982 with commercial operation on November 20, 1983, in accordance with the schedule advocated by O'Brien-Kreitzberg & Associates, Inc. (OKA).

Q. Please describe the results of your analysis of the financial impact on PECO if the PUC were to accept the positions of the various intervenors in this case.

A. Table 1 presents a summary of the details of various opposing party positions (i.e., Staff, OCA, City and GEC) in this case relative to the amount of the proposed rate increase, phase-in period, rate base disallowances, etc. Based on that information, Table 2 contains a summary of the financial results of the proposed rate increase positions of these opposing parties for the period 1987 to 1989. For reference, I have included the comparable numbers based on PECO's full rate request and assuming that PECO's request is adjusted to reflect the continuation of 50% of Limerick common plant in CWIP. My discussion of this data is divided into two parts. The first section discusses the financial impact of the proposed major reductions to the Company's overall revenue requirement. The second section addresses the financial impact of the major alternative phase-in plans proposed by opposing parties.

Q. Please discuss the financial impact of the rate proposals of the PUC Staff and OCA.

A. PUC Staff and OCA propose to disallow completely approximately $400 million of our rate request and would reduce our revenue requirements by another $140 million by keeping 50% of Limerick common plant in CWIP. It is readily apparent from an examination of Table 2 that the small rate increases (i.e., $134 - $152 million) proposed by these parties would cause serious financial harm to Philadelphia Electric Company and its customers. As shown below, I believe that these recommendations represent a completely unreasonable position which would cause irreparable harm to our customers, our investors and the economy of the Delaware Valley for many years to come.

As shown on Table 2, under the Staff's $152 million recommendation, the return on common equity would be about 9%, and our earnings per share in the 1987-89 period would be in the range of $1.49 to $1.63. These levels would be about 40% below our current earnings and 30% below our current dividend of $2.20 and would undoubtedly require a substantial cut in the Company's dividend to recognize the reduced earnings picture. AFUDC would exceed 70% of our earnings and would reach 106% in 1989. Our mortgage coverage ratio would fall below the minimum of 2.0 times, thereby preventing the issuance of any additional first mortgage bonds. SEC coverage without AFUDC would be 1.3-1.6 times in 1987-89, and cash flow as a percent of total capitalization would fall to 1.0%. These indicators are clearly unacceptable, as they fall within the BB rating range published by Standard & Poor's. It is my opinion that under these conditions, the Company would be in serious jeopardy of having its securities downgraded to the BB category, which would be below "Investment Grade." This would significantly impair the Company's ability to continue to attract capital. If we are forced to reduce our dividend as well, I believe we will be cut off from the capital markets and prevented from raising the capital required to provide service to future customers, particularly Limerick 2, which the Commission has recently determined to be the most economic way to provide additional generating capacity needed in 1991.

It should be emphasized that Table 2 has been prepared on the assumption that the proposed amendment to FASB 71, which would require an immediate write-off of prudency disallowances, would <u>not</u> apply to PECO in this period. If this proposed change is effective beginning in 1987, as is currently proposed, the Company would be required to write off the $1.1 billion prudency disallowance proposed by the Staff which would amount to about $1.0 billion after taxes. The implications of such a write-off are as follows:

(a) Earnings per share would be reduced by about $5.00 per share in the year of the write-off (probably 1986 or 1987).

(b) The Company's retained earnings would be reduced to a <u>negative</u> $416 million.

(c) The Company's total common stock equity account would be reduced to $2.21 billion which would represent only 29% of total capital and would place the Company in default of its credit agreements.

(d) The Company would be prevented from paying preferred and common stock dividends at least until retained earnings are restored to a positive value.

Under these conditions, the Company would be further inhibited in raising capital on reasonable terms to provide service to its customers.

The rate increase proposed by the OCA produces slightly worse financial results than Staff's proposal. Ignoring the implications of a cost disallowance under the proposed amendment to FASB 71, earnings per share would range from $1.45 to $1.52 per share, and our mortgage coverage ratio would decline below 2.0 times by 1988. It is my assessment that the same adverse repercussions outlined above for the PUC Staff's proposed rate increase would also befall PECO under the OCA rate plan. Moreover, my previous comments on the potential impact of the proposed amendment to FASB 71 relating to cost disallowances would also apply and would result in an after tax write-off of about $600 million.

Q. Please describe the financial impact of the various alternative phase-in plans proposed by the intervenors in this proceeding.

A. I have reviewed the phase-in proposals of City of Philadelphia Witness Palast, Governor's Energy Council (GEC) Witness Wilson, Philadelphia Area Industrial Energy Users Group (PAIEUG) Witness Falkenberg, Pennsylvania Business Utility Users Group (PBUUG) Witness King, and Utility Users Committee/University of Pennsylvania (UUC/UP) Witness Chernick and have determined that these plans would have an adverse impact on the Company's financial condition and its ability to raise capital at a reasonable cost. These phase-in proposals therefore should be rejected.

Q. Before addressing the specifics of the proposed phase-in plans, would you describe, in general terms, the potential impact of a phase-in program on the Company's financial position?

A. Yes. Several general points should be emphasized in reviewing the financial impact of the phase-in plans. First, the overall financial impact of a phase-in plan will depend, in part, on whether it complies with FASB 71. Assuming that a proposed phase-in plan complies with FASB 71, the Company will be able to accrue the deferred revenue on its current income statements. Under this scenario and assuming recognition of deferred revenues, the Company's earnings per share, return on equity and coverage ratios should not be significantly affected except that additional borrowings would be required to replace deferred revenue, which would reduce earnings and coverage ratios as compared with no phase-in of the rate increase. Conversely, if a phase-in plan does not comply with FASB 71, deferred revenue could not be reported currently, and there would be a serious adverse effect on all the Company's reported financial indicators.

Second, regardless of FASB 71 compliance, by delaying rate increases into the future, each of the phase-in plans will have a serious impact on the Company's quality of earnings indicators by reducing the Company's cash flow and by requiring additional borrowings to replace the deferred revenues. For example, under the plans proposed by intervenors, the Company would be required to borrow up to an additional $1.5 billion over the next five years, which could adversely affect the Company's bond ratings and restrict the amount that the Company would be able to finance in the capital market. This cash flow impact would occur during a period when the Company's external capital requirements already are expected to be in excess of $3 billion. These potential constraints on the Company's future cash flow position would jeopardize PECO's ability to meet refunding requirements, maintain existing utility plant, and complete capital additions to provide service to future customers.

The Commission has recently determined that the Company requires additional generating capacity by 1991 and that the completion of Limerick 2 under a cost containment program to provide that capacity is in the public interest. The adoption of the phase-in plans proposed by intervenors essentially denies the Company the cash flow to which it is entitled under traditional ratemaking principles, and which is necessary to complete Limerick 2. Such a result would be particularly troublesome when it is remembered that the principal impact of the phase-in plans is to defer the timing of rate increases into the future, thereby denying PECO cash flow when it needs it to provide service to ratepayers and imposing on future customers equal or larger rate increases than those proposed by the Company.

Third, it should be recognized that a phase-in plan longer than the Company's proposal would require recovery of the carrying charges on the deferred revenue in order to offset the significant cost of the additional borrowings and maintain the Company's earnings. I will discuss the specifics of this impact in connection with the City's phase-in proposal. Moreover, without provision for recovery of the carrying charges on deferred revenue, the proposed amendment to FASB 71 would require the Company to reduce current earnings to reflect the present worth of the loss of carrying charges. It should be noted that the negative cash flow constraints resulting from the various phase-in proposals discussed above are not alleviated by the allowance of a return on the deferred revenue balance. This is because additional external funding would be required to replace these deferred revenues.

Finally, the phase-in plans submitted by a number of intervenors assume that the Company's requested rate increase is granted in full or in full except for

50% of Limerick 1 common plant. Thus, if the full increase is not granted and the extended phase-in plans of intervenors are adopted, the financial impact would be even more devastating.

Q. Please comment specifically on the phase-in plan proposed by the City of Philadelphia.

A. City of Philadelphia Witness Palast proposes a seven-year phase-in of the Company's requested rate increase and a ten-year period for recovery of deferred revenue and makes no provision for the recovery of carrying charges on the deferred amounts. It should be noted that, while Witness Palast testifies that his 17-year phase-in will have only a "negligible" effect on the Company's financial condition, he has provided no analysis of his plan's impact on the future financial condition of the Company after 1986. Such analyses, as presented below, demonstrate that Witness Palast's plan would have a disastrous effect on the Company's future financial integrity and therefore should be rejected.

First, as set forth in the Rebuttal Testimony of David J. Farling (PECO Statement No. 16A), Witness Palast's plan does not comply with the proposed amendment to FASB 71 requiring that all revenue or costs deferred under a phase-in plan be recovered within 10 years. Therefore, if this amendment is adopted and the City's plan were accepted, there would be no current recognition of deferred revenue on the Company's financial statements. As shown on Table 2, the results are devastating. Earnings would drop from $2.56 per share in 1985 to $1.17 in 1987, $1.34 in 1988, and $1.59 in 1989, and the Company's return on common equity would fall to 6.8% in 1987, 8.4% in 1988, and 10% in 1989. SEC coverage ratios without AFUDC, would be only 1.6 times in 1987-88. AFUDC as a percent of total earnings would range between 75-80%, and cash as a percent of total capitalization would be 1%. Interest coverage under the mortgage which was 1.98 in 1985 will decline to 1.84 times in 1989 under Palast's 17-year proposal, which assumes that the Commission will grant the Company the full requested increase. These 1987-1989 financial indicators under the City's plan are significantly inferior in 1987 and similar in 1988 and 1989 to those under the Staff and OCA proposals.

Even assuming that the FASB 71 Exposure Draft is not adopted and that Witness Palast's phase-in plan complies with existing FASB 71, it would still have a devastating impact on the Company's financial condition and construction program. Under Witness Palast's plan, the Company would permanently lose $2 billion as a result of the denial of all carrying charges over the 17-year period. Over the first five years alone, the Company would have to borrow $1.5 billion in additional capital to replace lost cash flow and carrying charges thereon under Palast's plan. As a result, the Company's cash flow indicators would fall precipitously during this period. Cash flow as a percent of total capital would be 1.0% or less and internal sources as a percent of construction becomes negative in 1989, even assuming that the full rate increase is granted. These results would clearly preclude the Company from continuing its construction program.

Q. Please discuss the phase-in proposal of GEC Witness Wilson.

A. Witness Wilson, while discussing other various phase-in alternatives, proposes a ten-year phase-in deferral plan in connection with the use of sinking fund depreciation. While Witness Wilson's plan should produce earnings and coverages generally comparable with the Company's plan, the quality of earnings would be substantially inferior to the PECO plan because of lower revenue allowances associated with the longer phase-in and use of sinking fund depreciation.

Specifically, Witness Wilson's plan would result in a cumulative reduction in the Company's cash flow of approximately $900 million through 1991. This reduction in cash flow, though not as severe as Palast's, would place the Company in a weakened financial position and could significantly affect the Company's construction program. In addition, it should be noted that, while his proposal will impair the Company's financial condition, Witness Wilson's plan also will require additional revenues during the recovery period totaling $345 million to provide a return on the deferred balances. Thus, in essence, GEC's plan deprives the Company of needed cash flow during a critical construction period by imposing larger than necessary rate increases on future customers. Further, as explained by Mr. Farling, the GEC plan may not comply with existing and proposed generally accepted accounting principles.

Q. Are there any additional phase-in plans proposed by intervenors?

A. Yes. UUC/UP Witness Chernick recommends a plan which would match annual revenue allowances with anticipated annual benefits of operation of Limerick 1. Witness Chernick's plan does not ensure recovery of deferred revenue within a ten-year period and would therefore violate proposed FASB 71. Moreover, under Witness Chernick's proposal the Company would receive a net rate decrease in this case and would achieve financial results far worse than even the OCA, PUC Staff and City proposals discussed above.

PAIEUG Witness Falkenberg proposes the use of average Limerick revenue requirements, excluding 50% of common plant, over a six-year phase-in and the use of sinking fund depreciation for Limerick 1. The errors in the proposed use of the average annual revenue requirement for Limerick Unit 1 are addressed in the Rebuttal Testimony of Mr. Hill (PECO Statement No. 18D), and the problems with use of the proposed sinking fund method is discussed in the Rebuttal Testimony of Mr. Wroblewski (PECO Statement No. 21A). Both methods are contrary to normal and accepted ratemaking principles and should therefore be rejected. Witness Falkenberg's proposal would result in a cumulative reduction in the Company's cash flow of approximately $1 billion through 1991 which would have a similar negative impact on the Company's financial condition and construction program as the GEC plan.

Finally, PBUUG Witness King's proposal to establish a levelized payment schedule for Limerick 1 over its lifetime would result in a cumulative reduction of the Company's cash flow in excess $1 billion by 1991 and should be rejected for the reasons stated above.

Q. Mr. Paquette, do you have any comments on other proposals raised by opposing parties?

A. Yes. Several parties have proposed that the Company be required to guarantee the energy savings projected for Limerick 1. Such a guarantee would only further increase the financial risk faced by the Company and result in a further deterioration of the Company's financial condition in any year in which projected Limerick 1 energy savings were not achieved. The Company therefore cannot agree to guarantee the Limerick 1 energy savings. Similarly, Trial Staff's proposal to include 20% of total energy costs in base rates, subject to change only in a base rate case, would make it much more difficult for the Company to recover increases in energy costs on a timely basis. This would also increase financial risk and subject the Company to further deterioration of its financial condition beyond that which is shown on Table 2.

Q. Mr. Paquette, what are your conclusions regarding the major opposing party rate increase recommendations which have been presented in this case?

A. It is obvious that the extreme positions proposed by the PUC Staff, the OCA and the City of Philadelphia would cause irreparable harm to the Company, its shareholders and its customers. The GEC's position is more reasonable, but it contains fundamental timing problems which make it unfair to present and future ratepayers by jeopardizing the Company's construction program while at the same time imposing larger rate increases on future customers. I believe that only the Company's proposed rate increase and phase-in plan achieve the desired objective of balancing (1) the needs of our current customers who are being served by Limerick, (2) the needs of our future customers who must depend on the Company for an adequate and dependable supply of electricity for many years to come, (3) the interests of our investors who have provided the $3.8 billion of capital for Limerick in anticipation that the regulatory process would provide a fair return on and an orderly return of their investment, and (4) the requirements of the financial markets if we are to raise the capital for our future financial needs.

Q. Mr. Paquette, why did you develop a hypothetical financing plan consistent with the OKA construction schedule?

A. I am aware that Mr. Boyer's Supplemental Testimony documents his opinion that the Company could not have completed Limerick No. 1 before February 1986 even if there had been no cash constraints which limited the construction schedule in the 1970's. Nevertheless, I have developed a hypothetical financing plan which would be consistent with the OKA construction schedule. The purpose of this exercise is to develop data to be utilized by Mr. Hill in his assessment of the overall impact of the OKA plan on our revenue requirements over the entire construction phase and operating life of Limerick considering all appropriate factors. Specifically, my study will provide Mr. Hill with the change in revenue requirements that would have resulted from the OKA plan during the construction period and the changes that would have resulted in the Company's AFUDC rate as a result of the hypothetical financing plan.

Q. Mr. Paquette, would you now please discuss how the Company developed its hypothetical OKA financing schedule?

A. To accommodate the additional financing that would have been necessary to put Limerick Unit No. 1 in commercial operation on November 20, 1983, we have utilized the direct costs in the OKA proposed schedule (OCA Statement No. 1A) but have included the additional PURTA taxes and overheads which would have been capitalized, and we have utilized the recalculated AFUDC reflecting the AFUDC rate which would have been in effect under the hypothetical OKA financing program. Table 3 shows the yearly changes which the corrected OKA construction schedule would have produced in our financing program.

We have employed the most conservative assumptions in order to determine the specific nature and terms of the financing required each year. As will be discussed below, the OKA construction plan would have required us to raise $929 million of additional capital in the period 1975 to 1982. Despite the fact that the Company's actual financial condition was extremely weak during this period, we have assumed, for purposes of this study, that we would have raised that additional amount of capital without suffering any further downgrading in our security ratings.

In order to roughly simulate the same financial condition which actually existed, we adjusted revenue, up or down, each year to maintain earnings per share at exactly the same amount each year as was historically recorded. These revenue changes are employed by Mr. Hill to compute the impact on our customers' bills during the period 1975-1985. We also calculated the amount of revenue increases required to maintain the same mortgage coverage ratios throughout the construction period. This was necessary because simple maintenance of dollar earnings per share did not in fact maintain our financial position, but in fact permitted a significant deterioration.

In our hypothetical study, we attempted to add financing in a manner which duplicates our actual historical capitalization ratios as closely as possible. Where possible, we increased an actual financing, and, for the most part, we assumed no penalty for increasing the size of an issue. We increased the size of existing issues in whole dollar amounts or round share amounts to reflect the practicalities of the real world and limited the size of the issues to that which we felt were capable of being sold at the time. If we were required to create a new financing, we assigned a rate for comparably rated securities, obtained from Moody's historical data. The timing of each new issue was determined by the pattern of the actual financings so as to best fit in with the existing financing program. Our ability to sell mortgage bonds and preferred stock was governed by our coverage ratios.

Q. Would you please describe the hypothetical OKA financing changes year by year?

A. Yes. Table 4 shows a summary of the year-by-year changes which the OKA schedule would have required utilizing the assumptions listed above. Table 5 shows the details of each issue discussed below.

<u>1975 ($45.7 Million Required)</u>

To provide the additional financing of $45.7 million, we first assumed that the $80 million August mortgage bond issue was increased to $100 million. Next, the

September common stock issue of 6 million shares was increased by 1.3 million shares to raise an additional $15.9 million. The remaining $9.8 million was assumed to be raised from short-term debt.

1976 ($43.9 Million Required)

We assumed that the additional required financing of $43.9 million was raised through the sale of common stock and an increase in the short-term debt balance because the size of the actual mortgage bond issues and preferred stock issues could not have been increased. The October common stock sale was increased from 4 to 5.5 million shares, raising $26.3 million, and the short-term debt balance was increased by $17.6 million.

1977 ($58.9 Million Required)

The two actual issues of mortgage bonds in March and July were each $75 million, and we have assumed that each issue was increased to $100 million, representing the maximum size of an issue able to be sold at that time. In addition, we increased the size of the October common stock issue from 4 million to 5.2 million shares, raising another $24.2 million. This amount of assumed financing was in excess of the requirement and allowed us to reduce short-term debt by $15.3 million.

1978 ($86.4 Million Required)

We assumed that the size of the $100 million bond issue sold in March could not be increased. Therefore, in order to raise the necessary capital and to maintain historical capitalization ratios, we assumed a new issue of $75.0 million of mortgage bonds in September. The additional requirement of $11.4 million was raised through short-term debt.

1979 ($123.3 Million Required)

In 1979, the Company was still experiencing an inability to sell preferred stock due to insufficient coverages. Therefore, the amount to be financed is split between debt and common stock. Mortgage coverage was marginal at year-end; and, if the new issue were assumed to have been mortgage bonds in the beginning of the year, it might have jeopardized the actual October issue of $100 million of mortgage bonds. Therefore, it was assumed that $50 million of debentures would be issued in March. In addition, we assumed a 4 million share issue of common stock in October which raised $60 million. Short term debt was increased by $13.3 million to provide the remainder of the funds.

1980 ($178.4 Million Required)

At this time the Company was still experiencing coverage problems with respect to the issuance of debt. Therefore, we assumed the issuance of $100 million of debentures in July.

The Company actually sold $72 million of preferred stock, and it was assumed that additional preferred stock could not be sold.

The balance of the funds would be raised through the sale of 4 million shares of common stock in September in the amount of $57.5 million which followed the actual sale of 7 million shares in July. Short term debt was increased $20.9 million.

1981 ($230.6 Million Required)

In actual practice, the Company sold $424 million of debt in 1981 in the form of mortgage bonds and pollution control notes in sales in April, June, July and September. At this point in time, it is assumed that the Company could not have raised additional mortgage bonds and would have been required to sell debt in the form of debentures. Therefore, we assumed the sale of $125 million of debentures in December. There was no preferred stock actually sold in 1981, so we assumed a $50 million sale of preferred stock in February. The actual common stock issue in September was increased by 4 million shares to raise an additional $49.5 million, and the September common issue was increased by 1.2 million shares, which provides $15.3 million. These financings enabled us to reduce short term debt by $9.2 million.

1982 ($161.7 Million Required)

The Company sold $320 million of debt in 1982 in the form of mortgage bonds, pollution control notes and serial notes in March, June, September and December. It was assumed that any additional debt financing would have to be in the form of debentures. Therefore, we assumed a $100 million debenture issue in July. The Company sold $30 million of preferred stock in February which we assumed could be increased by $20 million to $50 million but at an increased cost of 17.50% (instead of 17-1/8%). We also assumed that both of the 6 million share common stock issues in April and October were increased by 3 million shares, raising an additional $90.4 million. Total financing would permit us to reduce short-term debt by $48.7 million.

1983 ($197.6 Million Lower Requirement)

As a result of the earlier in-service date of Limerick Unit No. 1 as proposed by OKA, the amount of financing required in 1983 would have been reduced by $197.6 million. At the end of 1983, the Company borrowed $200 million under its $400 million domestic revolving credit/term loan agreement. We assumed that this borrowing and also the $800 million Limerick Credit Agreement (LCA) would not have taken place if Limerick Unit No. 1 had been placed in commercial operation in 1983. However, in order to maintain the appropriate capitalization ratios, we have eliminated the sale of 6.0 million shares of common stock in March ($104 million) and substituted a $100 million issue of mortgage bonds. As a result, short-term debt would have to be increased by $6.4 million.

<u>1984 ($664.5 Million Lower Requirement)</u>

Likewise, in 1984 the amount of financing would have been reduced significantly. The required reduction is $664.5 million. The effect of this reduction would have been essentially to have eliminated all the equity financing -- both common and preferred -- except for that sold through the various stock plans. As noted above, we have eliminated the borrowings under the LCA as well as the pollution control financing for Limerick which would not have been possible under the OKA schedule. We have also assumed a new $100 million issue of mortgage bonds to maintain the appropriate capitalization ratios. As a result, short-term debt would have been reduced by $65.6 million.

<u>1985 ($473.4 Million Lower Requirement)</u>

The amount of financing reduction for 1985 would have amounted to $473.4 million. This would have resulted in the elimination of all equity financing, including the assumed elimination of the Company's Dividend Reinvestment and Stock Purchase Plan but maintaining the employee plans. Consistently with the above-mentioned assumptions, we eliminated the borrowing under the LCA and the Limerick pollution control financing. In addition, we reduced each of the November mortgage bond issues by $50 million. As a result, short-term debt would have increased by $44.2 million.

Q. Would you please summarize the changes that the hypothetical OKA financing plan would have produced?

A. Table 6 presents a summary of the capital structure that results from the hypothetical OKA financing plan for the period 1975 through 1985 as compared with the actual PE structure. As indicated on Table 6, the hypothetical OKA financing plan would have maintained the various capitalization ratios at a level very close to actual for every year in the study. In addition, our short-term position would have been reduced by only $15.2 million through December 31, 1985.

Table 7 shows a comparison of the key financial ratios (earnings per share, AFUDC as a % of earnings, mortgage coverage ratio and preferred stock ratio) for the hypothetical and actual financing programs. As indicated above, we programmed earnings per share under the hypothetical OKA plan to be identical to the actual earnings per share. However, the percentage of earnings represented by AFUDC increased significantly under the hypothetical plan in some years, resulting in a reduction in the quality of earnings. In addition, we would have experienced a lower mortgage coverage ratio during the entire period 1975 to 1983, inclusive, under the hypothetical OKA plan. Of particular concern is the period 1977 to 1981 when the OKA plan would have shown a serious decline in mortgage coverage, especially in 1979 when the ratio was only 1.88 times. I have calculated that approximately $195 million of additional revenue would have been required during the period 1975-83 to prevent this serious decline in mortgage coverage ratios under the OKA plan, in addition to the revenue needed to maintain earnings per share.

Q. Mr. Paquette, what are your conclusions regarding this study relating to the hypothetical OKA financing?

A. I believe that the hypothetical financing plan outlined is extremely optimistic in terms of the availability of capital and the cost of capital. In the period from 1973 to 1980, in particular, we were operating in a capital market environment which was extremely volatile and nervous. Even if we assume that it would have been possible to raise the required capital, it would probably have necessitated a significant increase in the cost of the capital and undoubtedly a downgrading of our security ratings, which would have further increased the costs of the OKA plan and resulted in higher rates for our customers.

Q. Mr. Sanders has expressed his opinion that the Company would have experienced a downgrading in its security ratings if it had attempted to pursue the OKA financing plan. Can you assess the cost impact of a downgrading if one had occurred in 1976?

A. If our mortgage bond rating had been downgraded to BBB in 1976, that would have probably increased the cost of all the securities we issued until 1983, assuming we were able to raise the required capital for the OKA plan. In addition, the market value of all our outstanding securities would probably have been adversely affected as well.

In the period 1976 through 1983, we would have been required to raise about $4.1 billion of new capital under the OKA plan. I believe that a downgrading to the BBB category in 1976 would have increased our overall cost of capital in this period by at least 50 basis points (0.50%). Thus, the increased cost on the full $4.1 billion of capital raised in the 1976 to 1983 period would have amounted to at least $20 million per year by 1983. Over the 1976-1983 period, the cumulative higher cost of capital would have amounted to at least $75 million. These costs have not been reflected in our analysis of the OKA construction plan.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Table 1

Comparison of Recommended
Rate Increases

	PUC Staff	OCA	City	GEC	PECo As Filed	PECo As Adjusted for 50% Common in CWIP
Revenue Requirement (Net) (Million $)	$152	$134	$671	$671	$671	$533
Phase In Plan						
Deferred Period	N/A	N/A	7 yrs	4 yrs	3 yrs	3 yrs
Collection Period			10 yrs	5 yrs	3 yrs	3 yrs
Total			17 yrs	10 yrs	5 yrs	5 yrs
Return on Def. Revenue	N/A	N/A	No	Yes	No	No
Common Plant Incl. in Rate Base	50%	50%	100%	100%	100%	50%
Rate Base Reduction (Million $)						
1976-1978 Delays	$1,094 (1)	$654 (2)	-	-	-	-
Mark II	-	194	-	-	-	-
50% Common	452	640	-	-	-	$640
Other	56	(70)	-	-	-	(32)
Total Reduction	$1,602	$1,418	-	-	-	$608
Recommended Rate Base(Estimated)	$5,342	$5,526 (2)	$6,944 (3)	$6,944 (3)	$6,944 (3)	$6,336 (3)
Proposed Return on Equity on Recommended Rate Base	14%-15%	14 %	15.93% (3)	15.93% (3)	15.93% (3)	15.93% (3)

(1) Includes effect on 100% of common
(2) Corrected for response to IR-PECo-OCA-10-1
(3) Based on Exhibit TPH-2A

Comparison of PE Financial Results Under Intervenor Rate Increase Recommendations

	PUC Staff	OCA	City	GEC	PECo As Filed	PECo As Adjusted for 50% Common in CWI
Earnings Per Share						
1987	$1.53	$1.52	$1.17	$2.56	$2.54	$2.57
1988	1.58	1.45	1.34	2.46	2.49	2.53
1989	1.49	1.45	1.59	2.57	2.61	2.64
Return on Equity						
1987	9.3%	8.7%	5.8%	13.9%	13.8%	13.9%
1988	9.4	8.8	8.4	13.3	13.5	13.5
1989	8.9	8.8	10.0	13.2	13.4	13.6
AFUDC in % Earnings						
1987	73 %	79 %	76 %	35 %	35 %	47 %
1988	86	93	79	43	43	54
1989	106	110	81	50	49	50
Mortgage Coverage (Accrued)						
1987	2.3 X	2.2 X	2.2 X	3.6 X	3.7 X	3.4 X
1988	1.8	1.7	2.1	3.1	3.3	3.0
1989	1.5	1.5	1.8	2.8	3.2	2.9
SEC without AFUDC						
1987	1.6 X	1.6 X	1.6 X	2.5 X	2.6 X	2.4 X
1988	1.5	1.4	1.6	2.4	2.5	2.3
1989	1.3	1.2	1.5	2.2	2.4	2.2
Internal Sources in % Construction w/o AFUDC						
1987	13.6%	11.4%	9.3%	21.4%	19.9%	18.1%
1988	(2.9)	(5.6)	6.1	29.0	47.1	41.0
1989	(37.7)	(39.6)	(7.2)	35.4	75.9	69.3
Cash Flow/Total Capital						
1987	1 %	1 %	1 %	4.3 %	5.9%	5.0%
1988	1	1	1	3.5	4.6	4.0
1989	1	1	1	2.4	2.9	2.0

Annual Changes to PE Financing
Program Required by OKA
Construction Schedule
(Million $)

	Change In		
	Direct Costs	AFUDC	Total Change
1975	$43.8	$1.9	$45.7
1976	39.6	4.3	43.9
1977	49.8	9.1	58.9
1978	72.0	14.4	86.4
1979	100.6	22.7	123.3
1980	140.7	37.7	178.4
1981	167.5	63.1	230.6
1982	76.2	85.5	161.7
1983	(280.1)	82.5	(197.6)
1984	(407.6)	(256.9)	(664.5)
1985	(149.7)	(323.7)	(473.4)
Total	($147.2)	($259.4)	($406.6)

Hypothetical Changes to Actual PE Financing Program
As a Result of OKA
Construction Schedule
(Million $)

	Debt						
	Mortgage	Debentures	STD	Credit Agreement	Preferred Stock	Common Stock	Total
1975	20.0		9.8			15.9	45.
1976			17.6			26.3	43.
1977	50.0		(15.3)			24.2	58.
1978	75.0		11.4				86.
1979		50.0	13.3			60.0	123.
1980		100.0	20.9			57.5	178.
1981		125.0	(9.2)		50.0	64.8	230.
1982		100.0	(48.7)		20.0	90.4	161.
1983	100.0		6.4	(200.0)		(104.0)	(197.
1984	(148.7)		(65.6)	(200.0)	(100.0)	(150.2)	(664.
1985	(141.0)		44.2	(150.0)		(225.6)	(473.
Total	(44.7)	375.0	(15.2)	(550.0)	(50.0)	(141.7)	(405.

2/15/86

PHILADELPHIA ELECTRIC COMPANY
LIMERICK I and COMMON
HYPOTHETICAL FINANCING CHANGES UNDER OKA CONSTRUCTION SCHEDULE
1975-1985

			Date Issued	Price or Rate
1975				
MB	$20.0 million	Size increase from $80 million to $100 million Due 2000	Aug. 6	11%
CMN	$15.9 million	Rights offering @ $12.25 1.3 million add'l shares	Sept. 17	$12.25/share
STD	$ 9.8 million	Balance = $9.8 million		7.9%
Amount Needed:	$45.7 million			
1976				
CMN	$26.3 million	1,500,000 add'l shares	Oct. 6	$17.50/share
STD	$17.6 million	Balance = $27.4 million		6.8%
Amount needed:	$43.9 million			

			Date Issued	Price or Rate
1977				
MB	$25.0 million	Size increase from $75 million to $100 million Due 2007	March 8	8.625%
MB	$25.0 million	Size increase from $75 million to $100 million Due 2003	July 6	8.625%
CMN	$24.2 million	1,200,000 add'l shares	Oct. 5	$20.125/share
STD	($15.3) million	Balance = $12.1 million		7.1%
Amount needed:	$58.9 million			
1978				
*MB	$75.0 million	New - Based on Moody's baa	Sept. 10	9.5%
STD	$11.4 million	Balance = $23.5 million		9.1%
Amount needed:	$86.4 million			
1979				
*DEB	$50.0 million	New - based on Moody's (10.5%) + 150 basis points	March 1	12.0%
*CMN	$60.0 million	4 million new shares based on 10/79 ESPP Price @$15.00	Oct. 15	$15.00/share
STD	$13.3 million	Balance = $36.8 million		12.7%
Amount needed:	$123.3 million			

* NEW ISSUE

			Date Issued	Price or Rate
1980				
*DEB	$100.0 million	New-based on Moody's baa (12.75%) + 150 basis points	July 1	14.25%
*CMN	$ 57.5 million	4 million new shares Based on ESPP Price of 8/80 @$14.375	Sept 2	$14.375/share
STD	$20.9 million	Balance = $57.7 million		15.3%
Amount needed:	$178.4 million			
1981				
*PFD	$ 50.0 million	Based on Moody's baa (14.8%)	Feb. 1	14.8%
CMN	$ 49.5 million	4 million add'l shares	April 2	$12.375/share
CMN	$ 15.3 million	1.2 million add'l shares	Sept 30	$12.75/share
*DEB	$125.0 million	New - based on Moody's baa (17.0%) + 150 basis points)	Dec. 1	18.5%
STD	$ (9.2)million	Balance = $ 48.5 million		18.9%
Amount needed:	$230.6 million			

* NEW ISSUE

			Date Issued	Price or Rate
1982				
PFD	$ 20.0 million	Size increase from $30 to $50 mill div. rate increase from $17.125 to $17.50	Feb 18	17.5%
CMN	$ 42.4 million	3 million add'l shares	April 6	$14.125/share
*DEB	$100.0 million	New - based on Moody's baa (17.1%) + 150 basis points)	July 1	18.6%
CMN	$ 48.0 million	3 million add'l shares	Oct. 6	$16.00/share
STD	($48.7) million	Balance = ($0.2) million		14.9%
Amount needed:	$161.7 million			
1983				
CMN	($104.0) million	Elimination of Common Stock issue 6.0 million shares	March 29	$17.40/share
*MB	$100.0 million	New - based on Moody's baa	March 29	11.25%
BOR	($200.0) million	Eliminate borrowing under $400 million domestic revolver	Nov. 16	11% - 12%
STD	$6.4 million	Balance = $6.2 million		10.8%
Amount needed:	($197.6) million			

* NEW ISSUE

1984			Date Issued	Price or Rate
PFD	($ 50.0) million	Eliminate 14.625% Preferred Stock	March 21	14.625%
CMN	($ 77.3) million	Elimination of Common Stock Issue 6 million shares	April 12	$12.875/share
*MB	$100.0 million	New - Based on Moody's baa (15.5%)	June 1	15.5%
CMN	($ 11.9) million	Elimination of Common Stock Issue 1 million shares-Continuous Offering	Aug. 1	$11.9/share
PC	($ 8.7) million	Eliminate Floating Rate Pollution Control Notes Due 2012	Sept. 28	Floating
CMN	($ 52.0) million	Elimination of Common Stock Issue 4 million shares	Oct. 4	$13.00/share
CMN	($ 9.0) million	Elimination of Common Stock Issue 612,900 shares-Continuous Offering	Nov 14	$14.7/share
PFD	($ 50.0) million	Eliminate $10 Depositary Preferred	Dec. 11	14.15%
BOR	($200.0) million	Eliminate net borrowing under Limerick Credit Agreement		
PC	($240.0) million	Eliminate Limerick Pollution Control Notes	Dec. 19	Variable @6.00 - 6.15%
STD	($65.6) million	Balance = ($59.4) million		12.0%
Amount needed:	($664.5) million			

* NEW ISSUE

1985			Date Issued	Price or Rate
MB	($ 50.0) million	Reduce 10.875% Mortgage Bonds Due 1995	Nov. 20	10.875%
MB	($ 50.0) million	Reduce 11.75% Mortgage Bonds Due 2014	Nov. 20	11.75%
CMN	($ 62.5) million	Elimination of Common Stock Issue 4 million shares	Nov. 14	$15.625/share
BOR	($150.0) million	Eliminate net borrowing under LCA	-	
PC	($41.0) million	Eliminate 10-1/2% Pollution Control Bonds	Nov. 11	10-1/2%
CMN	($53.4) million	Elimination of Common Stock Issue 3,387,000 shares of continuous offering	Jan. - Oct.	$15.77/share
CMN	($110.7) million	Elimination of Dividend Reinvestment Program 7.1 million shares	Jan. - Dec.	$15.59/share
STD	$ 44.2 million	Balance = ($15.2) million		9.5%
Amount needed:	($473.4) million			

* NEW ISSUE

Financial Division
2753K

Table 6

Comparison of Actual PECo Capital Structure
With Hypothetical OKA Financing Plan

	Debt Ratio - %		Preferred Ratio - %		Common Ratio - %		Average Number Common Stock - Shares		Cumulative Change
	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	OKA STD
1975	51.8%	51.9%	13.7%	13.5%	34.5%	34.6%	58,135	58,154	$9.8
1976	51.5	51.2	14.0	13.7	34.5	35.1	65,605	67,249	27.4
1977	51.7	51.6	13.1	12.7	35.2	35.7	70,844	73,919	12.1
1978	52.0	52.7	13.6	13.0	34.4	34.3	75,391	79,391	23.5
1979	52.3	52.9	12.8	11.9	34.9	35.2	80,529	85,362	36.8
1980	51.3	52.2	13.2	12.1	35.5	35.8	87,302	96,635	57.7
1981	51.7	52.5	11.9	11.3	36.5	36.2	99,557	114,857	48.5
1982	51.1	51.8	11.1	10.7	37.8	37.6	116,480	136,580	(0.2)
1983	50.0	50.8	11.9	11.7	38.0	37.5	133,852	152,552	6.2
1984	51.8	51.8	11.4	10.9	36.8	37.3	151,804	163,261	(59.4)
1985	51.8	51.6	10.5	10.7	37.7	37.8	169,784	169,628	(15.2)

2820K

Table 7

Comparison of Actual PECo Financial Ratios
With Hypothetical OKA Financing Plan

	Earnings Per Share		AFUDC % Earnings		Mortgage Coverage		Preferred Coverage	
	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical
1975	$1.86	$1.86	62.0%	63.2%	2.53 X	2.51 X	1.65 X	1.65 X
1976	1.91	1.91	61.8	63.8	2.48	2.47	1.65	1.67
1977	1.87	1.87	64.9	68.9	2.34	2.25	1.64	1.65
1978	1.87	1.87	64.4	71.0	2.35	2.14	1.59	1.57
1979	1.86	1.86	75.7	85.7	2.07	1.88	1.52	1.53
1980	2.00	2.00	84.3	95.9	2.25	2.06	1.58	1.57
1981	2.25	2.25	84.4	97.5	2.11	1.99	1.60	1.56
1982	2.39	2.39	76.5	91.5	2.42	2.35	1.71	1.67
1983	2.40	2.40	85.8	97.9	2.26	2.15	1.64	1.67
1984	2.70	2.70	86.5	22.2	2.55	4.46	1.75	1.77
1985	2.55	2.56	99.7	25.3	1.98	4.12	1.79	1.81

PECO STATEMENT NO. 3B

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

CORRECTED

REBUTTAL TESTIMONY OF

JOSEPH F. PAQUETTE, JR.

REVISED

FINANCIAL IMPACT OF

ADDITIONAL FINANCINGS

REQUIRED UNDER THE OKA

HYPOTHETICAL LIMERICK

CONSTRUCTION SCHEDULE

February, 1986

CORRECTED REBUTTAL TESTIMONY OF JOSEPH F. PAQUETTE, JR.

Q. Are you the same Joseph F. Paquette, Jr., who previously filed testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of this correction to your rebuttal testimony?

A. This correction to my rebuttal testimony adjusts my previous testimony to be consistent with the OKA Limerick Unit No. 1 construction schedule. In reviewing my prior analysis, it was discovered that we had not properly reflected all aspects of the OCA's proposed schedule related cost disallowances. Specifically, we had failed to recognize the OCA's proposed adjustments for Bechtel and PECO indirects which it is alleged would not have been incurred had Limerick been completed in November 1983.

Revised Table 3 shows the yearly changes which the corrected OKA construction schedule would have produced in our financing program.

Q. Mr. Paquette, in making the above detailed adjustments, has it been necessary to change the hypothetical financings detailed in Table 5 of your rebuttal testimony?

A. Yes. Revised Table 4 shows an overall summary of the year-by-year changes to the Company's historic financing schedule which would have been necessary to meet the OKA construction schedule incorporating the adjustments previously described. Revised Table 5 shows the detail of each financing. Specific changes to Table 5 in my rebuttal testimony include:

1975 to 1979 ($332.0 Million Required vs. $358.2 Million)

A reduction of $26.2 million from the $358.2 million total requirement identified in my rebuttal testimony would be absorbed through short-term debt.

1980 ($143.1 Million Required vs. $178.4 Million)

The new $100 million debenture issue sold in July was reduced to $75 million. The additional $10.3 million reduction was absorbed through short-term debt.

1981 ($178.2 Million Required vs. $230.6 Million)

The new $125 million debenture issue sold in December was reduced to $75 million. The additional $2.4 million reduction was absorbed through short-term debt.

1982 ($98.0 Million Required vs. $161.7 Million)

The new $100 million debenture issue sold in July was eliminated. The increase in the connom stock offering in October was reduced to an additional one million shares in order to maintain capitalization ratios. Short-term debt was then increased by $68.3 million.

1983 ($240.7 Million Lower Requirement vs. $197.6 Million Lower)

The new $100 million mortgage bonds issue sold in March was reduced to $75 million. The additional $18.1 million reduction was absorbed through short-term debt.

1984 ($675.6 Million Lower Requirement vs. $664.5 Million Lower)

The new $100 million mortgage bond issue sold in June was increased to $125 million. Additionally, the Company's Dividend Reinvestment and Stock Purchase Plan was eliminated, reducing common issued by 6.885 million shares. Short-term debt was increased $58.1 million.

1985 ($473.4 Million Lower Requirement vs. $473.4 Million Lower)

The November issuance of 11.75% mortgage bonds was increased by $50 million to $250 million - reversing the previous $50 million reduction. Short-term debt was decreased by $50 million

Q. Please summarize the changes that the revised hypothetical OKA financing plan would have produced.

A. Revised Table 6 presents a summary of the capital structure that results from the hypothetical OKA financing plan for the period 1975 through 1985 as compared with the actual PE structure. As indicated on revised Table 6, the hypothetical OKA financing plan would have maintained the various capitalization ratios at a level very close to actual for every year in the study. In addition, our short-term position would have been increased by only $4.2 million through December 31, 1985. Revised Table 7 shows a comparison of the key financial ratios (earnings per share, AFUDC as a % of earnings, mortgage coverage ratio and preferred stock ratio) for a hypothetical and actual financing programs. While we programmed earnings per share under the hypothetical OKA plan to be identical to the actual earnings per share, the percentage of earnings represented by AFUDC increased significantly under the hypothetical plan in some years, resulting in a reduction in the quality of earnings. In addition, we would have experienced a lower mortgage coverage ratio during the period 1975 to 1982, inclusive, under the revised hypothetical OKA plan. Of particular concern is the period 1977 to 1981 when the OKA plan would have shown a serious decline in mortgage coverage, especially in 1979 when the ratio was only 1.89 times. I have calculated that approximately $179 million of additional revenue would have been required during the period 1975-83 to prevent this serious decline in mortgage coverage ratios under the OKA plan, in addition to the revenue needed to maintain earnings per share.

Q. Mr. Paquette, what are your conclusions regarding this study relating to the hypothetical OKA financing?

A. I believe that the revised hypothetical financing plan outlined is extremely optimistic in terms of the availability of capital and the cost of capital. In the period from 1973 to 1980, in particular, we were operating in a capital market environment which was extremely volatile and nervous. Even if we assume that it would have been possible to raise the required capital, it would probably have necessitated a significant increase in the cost of the capital and undoubtedly a downgrading of our security ratings, which would have further increased the costs of the OKA plan and resulted in higher rates for our customers.

Q. Mr. Paquette, are these conclusions expressed above with respect to your revised analysis, the same as the conclusions you reached based upon your original analysis?

A. Yes, they are. These revisions to the original analysis are not significant and do not change any of the conclusions stated in my rebuttal testimony.

Q. Does this conclude your corrected rebuttal testimony?

A. Yes, it does.

Table 3

Annual Changes to PE Financing
Program Required by OKA
Construction Schedule
(Million $)

	Change In		
	Direct Costs	AFUDC	Total Change
1975	$38.7	$3.8	$42.5
1976	34.1	10.0	44.1
1977	42.7	19.8	62.5
1978	62.2	14.1	76.3
1979	85.9	20.7	106.6
1980	111.1	32.0	143.1
1981	121.7	56.5	178.2
1982	23.2	74.8	98.0
1983	(280.7)	40.0	(240.7)
1984	(408.7)	(266.9)	(675.6)
1985	(149.7)	(323.7)	(473.4)
Total	($319.5)	($318.9)*	($638.4)

*Includes ($317.9) million associated with Limerick No. 1 and 100% of common plant.

Table 4

Hypothetical Changes to Actual PE Financing Program
As a Result of OKA
Construction Schedule
(Million $)

	Debt						
	Mortgage	Debentures	STD	Credit Agreement	Preferred Stock	Common Stock	Total
1975	20.0		6.6			15.9	42.5
1976			17.8			26.3	44.1
1977	50.0		(11.7)			24.2	62.5
1978	75.0		1.3				76.3
1979		50.0	(3.4)			60.0	106.6
1980		75.0	10.6			57.5	143.1
1981		75.0	(11.6)		50.0	64.8	178.2
1982			19.6		20.0	58.4	98.0
1983	75.0		(11.7)	(200.0)		(104.0)	(240.7)
1984	(123.7)		(7.5)	(200.0)	(100.0)	(244.4)	(675.6)
1985	(91.0)		(5.8)	(150.0)		(226.6)	(473.4)
Total	5.3	200.0	4.2	(550.0)	(30.0)	(267.9)	(638.4)

2/25/86

PHILADELPHIA ELECTRIC COMPANY
LIMERICK I and COMMON
HYPOTHETICAL FINANCING CHANGES UNDER OCA CONSTRUCTION SCHEDULE
1975-1985

			Date Issued	Price or Rate
1975				
MB	$20.0 million	Size increase from $80 million to $100 million Due 2000	Aug. 6	11%
CMN	$15.9 million	Rights offering @ $12.25 1.3 million add'l shares	Sept. 17	$12.25/share
STD	$ 6.6 million	Balance = $6.6 million		7.9%
Amount Needed:	$42.5 million			
1976				
CMN	$26.3 million	1,500,000 add'l shares	Oct. 6	$17.50/share
STD	$17.8 million	Balance = $24.4 million		6.8%
Amount needed:	$44.1 million			

			Date Issued	Price or Rate
1977				
MB	$25.0 million	Size increase from $75 million to $100 million Due 2007	March 8	8.625%
MB	$25.0 million	Size increase from $75 million to $100 million Due 2003	July 6	8.625%
CMN	$24.2 million	1,200,000 add'l shares	Oct. 5	$20.125/share
STD	($11.7) million	Balance = $12.7 million		7.1%
Amount needed:	**$62.5 million**			
1978				
*MB	$75.0 million	New - Based on Moody's baa	Sept. 10	9.5%
STD	1.3 million	Balance = $14.0 million		9.1%
Amount needed:	**$76.3 million**			
1979				
*DEB	$50.0 million	New - based on Moody's (10.5%) + 150 basis points	March 1	12.0%
*CMN	$60.0 million	4 million new shares based on 10/79 ESPP Price @$15.00	Oct. 15	$15.00/share
STD	(3.4) million	Balance = $10.6 million		12.7%
Amount needed:	**$106.6 million**			

* NEW ISSUE

			Date Issued	Price or Rate
1980				
*DEB	$ 75.0 million	New-based on Moody's baa (12.75%) + 150 basis points	July 1	14.25%
*CMN	$ 57.5 million	4 million new shares Based on ESPP Price of 8/80 @$14.375	Sept 2	$14.375/share
STD	$10.6 million	Balance = $21.2 million		15.3%
Amount needed:	**$143.1 million**			
1981				
*PFD	$ 50.0 million	Based on Moody's baa (14.8%)	Feb. 1	14.8%
CMN	$ 49.5 million	4 million add'l shares	April 2	$12.375/share
CMN	$ 15.3 million	1.2 million add'l shares	Sept 30	$12.75/share
*DEB	$ 75.0 million	New - based on Moody's baa (17.0%) + 150 basis points)	Dec. 1	18.5%
STD	$(11.6)million	Balance = $ 9.6 million		18.9%
Amount needed:	**$178.2 million**			

* NEW ISSUE

			Date Issued	Price or Rate
1982				
PFD	$ 20.0 million	Size increase from $30 to $50 mill div. rate increase from $17.125 to $17.50	Feb 18	17.5%
CMN	$ 42.4 million	3 million add'l shares	April 6	$14.125/share
CMN	$ 16.0 million	1 million add'l shares	Oct. 6	$16.00/share
STD	$19.6 million	Balance = $29.2 million		14.9%
Amount needed:	**$98.0 million**			
1983				
CMN	($104.0) million	Elimination of Common Stock issue 6.0 million shares	March 29	$17.40/share
*MB	$ 75.0 million	New - based on Moody's baa	March 29	11.25%
BOR	($200.0) million	Eliminate borrowing under $400 million domestic revolver	Nov. 16	11% - 12%
STD	($11.7)million	Balance = $17.5 million		10.8%
Amount needed:	**($240.7) million**			

* NEW ISSUE

1984			Date Issued	Price or Rate
PFD	($ 50.0) million	Eliminate 14.625% Preferred Stock	March 21	14.625%
CMN	($ 77.3) million	Elimination of Common Stock Issue 6 million shares	April 12	$12.875/share
*MB	$125.0 million	New - Based on Moody's baa (15.5%)	June 1	15.5%
CMN	($ 11.9) million	Elimination of Common Stock Issue 1 million shares-Continuous Offering	Aug. 1	$11.9/share
PC	($ 8.7) million	Eliminate Floating Rate Pollution Control Notes Due 2012	Sept. 28	Floating
CMN	($ 52.0) million	Elimination of Common Stock Issue 4 million shares	Oct. 4	$13.00/share
CMN	($ 9.0) million	Elimination of Common Stock Issue 612,900 shares-Continuous Offering	Nov 14	$14.7/share
PFD	($ 50.0) million	Eliminate $10 Depositary Preferred	Dec. 11	14.15%
BOR	($200.0) million	Eliminate net borrowing under Limerick Credit Agreement		
PC	($240.0) million	Eliminate Limerick Pollution Control Notes	Dec. 19	Variable @6.00 - 6.15%
	($94.2) million	Eliminate Dividend Reinvestment Program 6,885,000 shares		$13.68/Share
STD	($7.5) million	Balance = ($10.0) million		12.0%
Amount needed:	($675.6) million			

* NEW ISSUE

1985			Date Issued	Price or Rate
MB	($ 50.0) million	Reduce 10.875% Mortgage Bonds Due 1995	Nov. 20	10.875%
CMN	($ 62.5) million	Elimination of Common Stock Issue 4 million shares	Nov. 14	$15.625/share
BOR	($150.0) million	Eliminate net borrowing under LCA	-	
PC	($41.0) million	Eliminate 10-1/2% Pollution Control Bonds	Nov. 11	10-1/2%
CMN	($53.4) million	Elimination of Common Stock Issue 3,387,000 shares of continuous offering	Jan. - Oct.	$15.77/share
CMN	($110.7) million	Elimination of Dividend Reinvestment Program 7.1 million shares	Jan. - Dec.	$15.59/share
STD	$(5.8) million	Balance = ($4.2) million		9.5%
Amount needed:	($473.4) million			

* NEW ISSUE

Financial Division
2753K

Table 6

Comparison of Actual PECo Capital Structure
With Hypothetical OKA Financing Plan

	Debt Ratio - %		Preferred Ratio - %		Common Ratio - %		Average Number Common Stock - Shares		Cumulative Change
	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	OKA STD
1975	51.8%	51.9%	13.7%	13.6%	34.5%	34.6%	58,135	58,154	$6.6
1976	51.5	51.2	14.0	13.7	34.6	35.1	65,605	67,249	24.4
1977	51.7	51.6	13.1	12.7	35.2	35.7	70,844	73,919	12.7
1978	52.0	52.7	13.6	13.0	34.4	34.3	75,391	79,391	14.0
1979	52.3	52.9	12.8	11.9	34.9	35.2	80,529	85,362	10.6
1980	51.3	52.0	13.2	12.1	35.5	35.9	87,302	96,635	21.2
1981	51.7	51.9	11.9	11.4	36.5	36.7	99,557	114,857	9.6
1982	51.1	50.7	11.1	11.0	37.8	38.3	116,480	136,109	29.2
1983	50.0	49.7	11.9	12.1	38.0	38.2	133,852	150,552	17.5
1984	51.8	51.6	11.4	11.3	36.8	37.1	151,804	157,818	10.0
1985	51.8	51.7	10.5	11.0	37.7	37.4	169,784	160,743	4.2

Table 7

Comparison of Actual PECo Financial Ratios
With Hypothetical OKA Financing Plan

	Earnings Per Share		AFUDC % Earnings		Mortgage Coverage		Preferred Coverage	
	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical	Actual	Hypothetical
1975	$1.86	$1.86	62.0%	64.9%	2.53 X	2.47 X	1.65 X	1.65 X
1976	1.91	1.91	61.8	68.2	2.48	2.38	1.65	1.67
1977	1.87	1.87	64.9	76.6	2.34	2.10	1.64	1.65
1978	1.87	1.87	64.4	70.8	2.35	2.14	1.59	1.57
1979	1.86	1.86	75.7	84.4	2.07	1.89	1.52	1.52
1980	2.00	2.00	84.3	92.9	2.26	2.09	1.58	1.57
1981	2.25	2.25	84.4	94.9	2.11	1.99	1.60	1.58
1982	2.39	2.39	76.5	88.6	2.42	2.33	1.71	1.73
1983	2.40	2.40	85.8	87.5	2.26	2.33	1.64	1.71
1984	2.70	2.70	86.6	20.6	2.55	4.31	1.75	1.79
1985	2.56	2.56	99.7	26.7	1.98	3.79	1.79	1.80

PECO STATEMENT NO. 3C

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Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKETED
MAR 24 1986

DOCKET NO. R-850152

SUR-SURREBUTTAL TESTIMONY

OF

JOSEPH F. PAQUETTE, JR.

MARCH 1986

SUR-SURREBUTTAL TESTIMONY OF JOSEPH F. PAQUETTE, JR.

Q. Mr. Paquette, have you previously presented Direct and Rebuttal Testimony in this proceeding?

A. Yes, I have previously submitted Direct Testimony and Rebuttal Testimony identified as Company Statements 3, 3A and 3B.

Q. Mr. Paquette, what is the purpose of your Sur-surrebuttal Testimony?

A. This testimony will address certain comments made by Mr. Palast in his Surrebuttal Testimony, specifically: (1) the impact of PECo's phase-in proposal on earnings per share; (2) the impact of the City's phase-in proposal on the financial indicators of the Company; and (3) the characterization of carrying charges associated with Limerick over the 17-year period of the City's plan. In addition, I will respond to Mr. Lanzalotta's Surrebuttal Testimony concerning the Company's willingness to sell or share portions of our base load capacity.

Q. Please discuss Mr. Palast's statements concerning the impact of PECo's phase-in proposal on earnings per share.

A. With regard to the 1989 earnings per share comparison I presented in Table 2 of my Rebuttal Testimony, Mr. Palast, on pages 7 & 8 of his Surrebuttal Testimony, states:

> "If one were to subtract all deferred income from PECo's own plan, the results would not be much different than under the City's plan."

This statement is wrong. The Company's proposal consists of a three-year phase-in and three-year phase-out plan. Under our proposed phase-in, assuming a rate increase effective date of 6/27/86, the final step will be effective on 6/27/88, and therefore all revenues recorded from that date on will reflect the full increase. No additional accruals of deferred revenue are required. Consequently, our projected 1989 earnings per share of $2.61 would <u>not</u> be reduced due to elimination of deferred revenue since there are no deferred revenues accrued in that year. This is not true for the City's proposed phase-in plan.

Q. Please discuss Mr. Palast's statements concerning the impact of the City's phase-in proposal on the financial indicators of the Company.

A. The financial indicators of the Company are developed in accordance with generally accepted accounting principles. If the Commission were to accept the City's 17-year phase-in proposal and the changes to FASB-71 were adopted as currently proposed, the Company would not be permitted to include the deferred revenue in any statements prepared for financial reporting purposes. Consequently, the indicators I developed as a result of my analysis of the City's 17-year phase-in proposal are accurate representations of the data the investment community would utilize in their evaluation of the financial condition of PECo.

The Sur-surrebuttal Testimony of Mr. Sanders addresses the investment community's reaction to these seriously deficient financial indicators resulting from the City's proposed 17-year phase-in plan. Moreover, my own experience in dealing with investment firms, banks, brokers, institutional investors and individual investors indicates that the data contained in the Company's financial statements are utilized extensively as reported and are the basis for most investment decisions. The primary reason for investors' reliance on these reported statistics is their awareness that the Company is in compliance with all generally accepted accounting principles. These principles are developed to ensure that the statistics presented by the Company are an accurate representation of its financial condition and are valid measures for comparison with other companies. Thus, in response to

Mr. Palast's question on page 9 of his testimony, I firmly believe that investors would react the <u>same</u> to the OCA and City proposals during the 1987-89 time frame, as they would produce essentially the same reported financial results.

Q. Mr. Palast states that, if deferred revenues were currently reflected in his phase-in plan, most major financial indicators would not be seriously affected. Is this true?

A. No, it is not. Even if deferred revenues were currently recorded on the income statement, cash flow indicators would be exactly the same, as shown on Table 2 of my rebuttal testimony, and the Company would still suffer a $2 billion loss over the course of his 17-year phase-in.

Q. Please discuss Mr. Palast's statement concerning the carrying charges associated with Limerick 1 over the 17-year phase-in plan of the City.

A. On page 10 of his Surrebuttal Testimony, Mr. Palast states:

> "During the 17 year period of our (the City) plan, the public will pay approximately $13 billion to PECo for Limerick 1 charges, most of which represent profit or interest."

To begin, the $13 billion figure cited by Mr. Palast overstates the cost of Limerick 1 to our ratepayers. The $13 billion reflect only the cost associated with Limerick plant investment, including capital additions, and projected O&M expenses, but fail to reflect the approximate $14 billion of benefits of Limerick 1 for fuel savings and avoided capacity charges for the 17-year period.

With regard to Mr. Palast's assertion that most of the $13 billion represent "profit or interest," the actual components of the cited $13 billion, which were developed from the data provided in response to IR-OCA-2-25, are as follows:

	Cost in Billion $	% of Total
Operating and Maintenance Expenses	$3.3	25.4%
Taxes	3.3	25.4
Depreciation	1.5	11.5
Interest Expense	2.3	17.7
Preferred Dividends	0.5	3.8
Return on Common Equity	2.1	16.2
	$13.0 Billion	100.0%

As this summary indicates, only 37.7% of the $13.0 billion represents profits or interest, and only 16.2% represents "profit," standing alone. Thus, once again Mr. Palast's statements are not supported by the facts.

Concerning Mr. Palast's criticism of my Rebuttal Statement, there is nothing misleading about my conclusion that the Company would lose $2 billion as a result of the denial of all carrying charges over the City's 17-year plan. Under the City's plan the cumulative deferred revenue balance increases to a high of $2.0 billion in 1991 and 1992, and is not eliminated until 2002. Over this period the average annual deferred revenue balance is approximately $1.2 billion which represent dollars which the Company would otherwise have available to partially finance its various capital requirements as discussed in my Rebuttal Testimony. The City's proposal does not remove the Company's responsibility to provide reliable service; consequently, the Company will be forced to replace these deferred revenues via additional borrowings. If, as the City recommends, the Company is not permitted to recover the cost of these borrowed funds, the Company will be required to absorb these costs. The absorption of these costs will significantly reduce the equity return on Limerick 1 for 17 years.

Q. Please respond to Witness Palast's alternative 10-year phase-in.

A. While Witness Palast's 10-year phase-in plan provides some improvement in the major financial indicators when compared with his previously proposed 17-year plan, as shown on Table 1, it would still have serious impact on the financial condition of the Company. First, extending the phase-in to 10 years causes a tremendous reduction in internal sources of funds. Under the 10-year plan, internal sources as a percentage of construction expenditures (without AFUDC) ranges from 15% to 20%, whereas under the Company's proposal it ranges from 20% to 76%. Second, the lower level of internal sources of funds would require the Company to raise in excess of $1 billion of additional funds during the 1986 to 1991 period. In addition to the internal sources indicator, the cash flow as a percent of total capitalization is significantly lower under the 10-year plan versus the Company's proposal. It should also be noted that the decline in the return on equity under Witness Palast's proposal will continue until 1995, which is the end of Mr. Palast's stay-out period.

Finally, Witness Palast's proposal to bar PECo from seeking any additional rate increases (base or fuel) for the entire ten-year period would be highly deleterious. Neither the Company, the Commission, nor Witness Palast knows what the future will bring in terms of inflation levels or other forces that may adversely affect and thereby increase the revenue requirement which must be allowed to produce just and reasonable rate levels. Consequently, I believe that this alternative proposal of Mr. Palast as well as his original 17-year proposal should not be considered by this Commission as viable alternatives to the Company's original plan.

Q. Mr. Lanzalotta refers to PECo's "repeated attempts to sell substantial base-load capacity." Please explain the reasons that PECo undertook to sell portions of its base-load capacity?

A. During the mid to late 1970's and the early 1980's, Philadelphia Electric Company actively engaged in several attempts to sell or share portions of the output of Limerick as well as Salem Unit #2.

The resultant offers to sell or share base load capacity considered both the requirements for Philadelphia Electric Company System as well as the derived financial benefits that would have accrued to the Company and our customers by maintaining earlier in-service dates for these facilities. Of principal importance as a motivating factor for the Company was the fact that a sale would have provided an additional source of capital to the Company to hopefully maintain the Limerick construction activities.

All attempts to sell or share portions of Limerick were unsuccessful primarily because a sale could not be arranged which would have obtained the substantial early financial benefits which were our principal motivation. Also, sales and sharing arrangements could not be arranged upon terms which would be beneficial to ratepayers and shareholders as compared to maintaining plant availability. The possible adverse effects of such arrangements upon plant NRC licensing was also a consideration.

Q. Mr. Paquette, do these efforts to sell or share Limerick capacity indicate a Company determination that all or portions of the Limerick 1 capacity is not needed, as argued by Mr. Lanzalotta?

A. No, they do not. These efforts were directed at achieving capacity sharing arrangements with surrounding utilities also building nuclear power plants (i.e., PSE&G and PP&L) or short-term energy and/or capacity sales. By achieving such arrangements, it was hoped that total ratepayer costs could be reduced. This proved infeasible, as described above. None of these efforts reflected a Philadelphia Electric Company determination, as argued by Mr. Lanzalotta, that Limerick or any other base load capacity was not needed to serve our customers. As described by Mr. Rush and Dr. Hieronymus, the Company firmly believes that Limerick is needed to meet customer service requirements and will produce economic benefits for customers over its life-time.

Q. Does this conclude your Sur-surrebuttal Testimony?

A. Yes.

Comparison of PE Financial Results Under Intervenor Rate Increase Recommendations

	Palast 10 Year Plan	PECo As Filed
Earnings Per Share		
1987	$2.50	$2.54
1988	2.41	2.49
1989	2.45	2.61
Return on Equity		
1987	13.6%	13.8%
1988	13.1	13.5
1989	12.8	13.4
AFUDC in % Earnings		
1987	36 %	35 %
1988	44	43
1989	53	49
Mortgage Coverage (Accrued)		
1987	3.6 X	3.7 X
1988	3.0	3.3
1989	2.7	3.2
SEC without AFUDC		
1987	2.5 X	2.6 X
1988	2.1	2.5
1989	2.2	2.4
Internal Sources in % Construction w/o AFUDC		
1987	16.1%	19.9%
1988	19.5	47.1
1989	17.6	75.9
Cash Flow/Total Capital		
1987	5.4%	5.9%
1988	3.7	4.6
1989	1.7	2.9

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PENNSYLVANIA PUBLIC UTILITY COMMISSION
v. PHILADELPHIA ELECTRIC COMPANY,
DOCKET NO. R-850152

REBUTTAL TESTIMONY OF SALOMON LEVY

MARK II CONTAINMENT ISSUES

FEBRUARY 19, 1986

REBUTTAL TESTIMONY OF SALOMON LEVY

Q. Please state your name and business address for the record.

A. My name is Salomon Levy. I am founder and President of S. Levy, Incorporated, 3425 S. Bascom Avenue, Campbell, California 95008.

Q. Describe briefly your educational background.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of California at Berkeley in 1949, a Masters Degree in Mechanical Engineering from Berkeley in 1951, and a Ph.D. in Mechanical Engineering from Berkeley in 1953.

Q. Please describe the business of S. Levy Incorporated?

A. S. Levy, Incorporated is an Engineering/Management Consulting firm. The firm has been involved in a large number of projects to assist industry and government clients in various areas of nuclear power regulation and operation, including among others: (1) consulting in the preparation of reports on the resolution of the Mark II and TMI accident issues; (2) development of computer modeling systems; (3) assistance in nuclear licensing activities; (4) performance of nuclear safety analyses; and (5) development of a computer system used in the Safety Parameter Display Systems at nuclear plants.

Q. Please describe your professional experience since founding S. Levy Inc.

A. Since founding the Company in 1977, I have been involved in many activities related to the safety regulation of nuclear power plants, including the characterization and design resolution of containment hydrodynamic loads at various nuclear power plants. Among many other assignments, I have been a member of the Industry Advisory Board during the TMI incident, a consultant to the Staff of the Kemeny Commission and the Brookhaven National Laboratory, a member of two independent nuclear overview boards, a consultant to the Nuclear Regulatory Commission on the Advanced Code Review Committee, and a member of four Probabilistic Review Assessment (PRA) Boards. I have been the Springer Professor of Engineering at the University of California, Berkeley, a consultant to the World Bank/UNDP on nuclear safety in Korea, a Vice-Chairman on the Management Committee of CBI Nuclear, a member of the AEC Task Force on Emergency Core Cooling, and a member of the Review Committee on Reactor Safety at the Argonne National Laboratory. I am presently Chairman of The American Nuclear Society's Thermal Hydraulics Division and an Adjunct Professor of Engineering at the University of California at Los Angeles. I am also on the Board of Directors of Iowa Electric Company.

Q. Please describe your professional experience prior to founding S. Levy Inc.

A. Prior to 1977, I was employed at General Electric Company where for 24 years I worked on the development, safety analysis, design, manufacturing, and operation of nuclear power plants. In the mid-1950's, as Supervisor of GE's Atomic Power Equipment Department, I was responsible for the design, safeguard analyses, and development of small atomic power plants and test reactors. At this time, I was involved in aspects of the Humboldt Bay containment pressure predictions described later in this testimony. In the 1959 to 1966 period, I was responsible for GE's work on heat transfer and fluid flow development in BWRs. From 1966 to

1968, as Manager of Systems Engineering in the Atomic Power Equipment Department, I was responsible for conceiving and defining nuclear power plant systems for all requisition and proposal plants and all near-term improvements in nuclear power plant systems, including analyses of containment design adequacy. In the 1968 to 1971 period, I was responsible for all nuclear systems being offered by GE and all recent and future project management functions of domestic nuclear systems, which included development of the Mark II concept. In the mid-1970's, as General Manager of the Boiling Water Reactor Systems Department, I was responsible for the design and development of nuclear systems, including containment. Finally, from 1975 to my departure from GE in October, 1977, I was General Manager of GE's Boiling Water Reactor Operations, where I supervised the engineering and manufacturing of all GE BWRS. Thus, I have had an intimate involvement with the analyses of containment adequacy and the development of the Mark II design.

Q. Have you previously been involved in regulatory proceedings?

A. I have been involved in a number of formal NRC licensing and safety review proceedings, where I have been requested to present my analyses of the adequacy of design of nuclear power plants.

Q. Are you a member of any professional organizations?

A. Yes. I am a Member of the National Academy of Engineering, a Fellow of the American Society of Mechanical Engineers (ASME), and a Member of the American Nuclear Society.

As Schedule 1 to this testimony, I have attached my curriculum vitae. Also attached as Schedule 2 is a list of my publications, most of which have been on two-phase flow and boiling heat transfer, topics relevant to the subject of this testimony.

Q. Dr. Levy, what is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the error in the allegation of Dr. Stephen Hanauer that the Mark II containment design initially employed at Limerick contained an avoidable technical error. In addition, I will demonstrate that Dr. Hanauer has significantly overstated the safety concerns associated with the Mark II hydrodynamic loads which form the basis of his testimony. To demonstrate these errors, I will provide a brief history of the development of the pressure suppression concept for use in nuclear power plant containments, of the evolution of the NRC seismic and other requirements directed at containment design and of the hydrodynamic loads issue, and the ultimate NRC and industry resolution of that issue.

Q. Dr. Levy, what are Dr. Hanauer's principal allegations to which you will be responding?

A. First, Dr. Hanauer alleges that GE and PECO should have recognized and provided for certain hydrodynamic loads which affect Mark II containments prior to initiation of Limerick licensing and construction. Second, Dr. Hanauer understates the AEC/NRC involvement in the development and design of the Mark II containment and in the resolution of the hydrodynamic loads issue. Finally, Dr. Hanauer erroneously asserts that, because of the unrecognized loads, the original Limerick containment design posed a substantial safety concern to the public as it could have failed under operating or accident conditions.

Q. What is your response to these allegations?

A. I believe each of these assertions is very clearly in error. The characterization and significance of the hydrodynamic loads referenced by Dr. Hanauer were not known by utilities, vendors or the AEC until after Limerick licensing and construction was initiated. Immediately following recognition of the significance of these loads, an intensive effort was begun to characterize and design for them. However, because of the complexity of the matter and the substantial lack of information respecting the nature or effects of these loads, this program required a full seven years to be successfully completed. Indeed, the length and complexity of this program, its many iterations of testing and evaluation, clearly establish the error of Dr. Hanauer's position. Certainly, if the loads had been so obvious that their non-recognition prior to the 1974-1975 time period could constitute "technical error", then it would not have taken seven years for the combined resources of the NRC, the BWR utilities, GE and many other domestic and foreign contractors to define their nature and develop design solutions.

Also, Dr. Hanauer very cleary misstates the AEC's role both in nuclear regulation generally and as respects review and approval of the Mark II containment concept. The AEC had representatives present at the early tests which demonstrated the feasibility of the pressure suppression containment concept, extensively reviewed the test data and the early containment design evaluations, and even directed retesting of certain aspects of the design. Similarly, the AEC reviewed and approved the original Mark II designs, including that of Limerick, without raising any concerns respecting hydrodynamic loads.

Indeed, the AEC was aware of all of the operating plant and other data presented by Dr. Hanauer, was actively reviewing and increasing the stringency of containment design forcing conditions in the late 1960's and early 1970s and yet did not raise the hydrodynamic loads as a serious concern until their April 1975 letters to BWR Mark I and Mark II owners.

Finally, it is clear, both on technical grounds and from their treatment by the AEC/NRC, that these hydrodynamic loads do not approach the safety significance ascribed to them by Dr. Hanauer.

I. THE DEVELOPMENT OF THE MARK II PRESSURE SUPPRESSION CONTAINMENT

Q. Dr. Levy, please briefly describe BWR containment designs.

A. All Boiling Water Reactors (BWRs) are housed in a containment structure which protects the environment from any radioactivity that may accidentally be released from the nuclear fuel and the high pressure steel systems which house that fuel. The first BWRs (e.g. Dresden-1, Big Rock Point) employed a dry containment, which is a large volume spherical or cylindrical steel or concrete structure capable of withstanding the pressure and temperature resulting from the unexpected escape of the high pressure water/steam used to cool the nuclear fuel. In the period 1958 to 1962, General Electric Company, working with Pacific Gas and Electric Company, developed a new containment concept in which any escaping water/steam mixture from the reactor coolant system was quenched in a pool of water. This novel approach was referred to as pressure suppression containment because the containment returned essentially to atmospheric pressure shortly after the accident. This containment type was believed to have safety advantages over dry containment because the leakage of radioactivity from the containment to the environment would be reduced due to the small driving pressure between the inside and outside of the containment walls. Also, a large portion of the released radioactivity was expected to be trapped in the suppression pool.

The pressure suppression containment was first utilized at the Humboldt Bay Nuclear Power Plant, which was licensed for operation on August 28, 1962. Since that time, three different designs of pressure suppression containment have been constructed and put into operation. The Mark I, Mark II, and Mark III designs, shown schematically in Schedule 3, all have a drywell in which the reactor vessel and the reactor coolant system are housed, a suppression chamber (wetwell) half filled with water, and vent pipes connecting the drywell to the suppression chamber. In the event of a postulated leak or breach in the reactor coolant system, a water/steam mixture is released into the drywell which causes the drywell pressure to rise and the drywell atmosphere to flow through the vents into the water of the suppression chamber. The traveling steam is condensed in the suppression pool and the entrained air and other non-condensible gases bubble to the surface of the suppression pool and collect above it in the suppression chamber. Eventually, the steam flow through the vents stops, and the drywell and suppression chamber reach equilibrium pressures.

Q. Please now describe the Limerick containment.

A. The Limerick Generating Station utilizes the Mark II design. The vent pipes are vertical and the Limerick drywell and wetwell employ reinforced concrete structures. This Limerick Mark II design has several safety advantages over earlier designs. Its straight vent pipe configuration reduces the peak design pressure of the containment. Also, the reinforced concrete at Limerick is much more capable of withstanding the impact of any presumed broken high pressure pipe whipping within the containment than is the Mark I design.

Q. Dr. Levy, what is the basis for the design of the BWR Mark II containment?

A. The design basis for pressure suppression containments has always been the energy released from the hypothetical assumption of an instantaneous rupture of the largest pipe in the reactor coolant system (i.e., a substantial loss-of-coolant accident or LOCA). This assumption has been the basis of containment design because it is as the result of such an event that the maximum steam pressure is developed which must be contained. The containment also is designed to successfully withstand the largest earthquake ever recorded in the region where the plant is located. While these basic design requirements have not changed since the 1950s, there were many changes over the years in related NRC requirements:

-in addition to the energy released from the largest and instantaneous pipe LOCA, it became necessary to cope with fuel cooling, broken pipe whipping, and local pressure increases produced by the postulated LOCA event;

-the impact of safety relief valve actuation;

-the magnitude of the earthquake (seismic) loads kept increasing and the methods by which they were specified and calculated became more and more conservative;

-the LOCA, seismic, relief valve and other loads had to be combined;

-the margins to be provided in the containment design were increased.

Q. Please describe the safety relief valves used in the Mark II containment.

A. All BWRs are equipped with a number of safety relief valves (SRVs) to maintain the pressure of the reactor vessel and its connected piping below that prescribed by the Codes of the American Society of Mechanical Engineers (ASME). The SRVs are mounted inside the drywell on the pipes which carry steam from the reactor vessel to the turbine-generator. The exhaust from the SRVs is piped from the valves through the drywell and into the suppression pool. The relief valves are automatically actuated during rapid pressure increases, and also can be opened by plant operators to reduce reactor vessel pressure. In addition, a pre-selected number of relief valves open automatically to reduce the reactor pressure when the water level is low in order to permit several low pressure emergency core cooling systems to inject water into the reactor vessel.

After actuation of an SRV, the air-column within the discharge line is compressed by the released high pressure steam and the water leg in the suppression pool at the end of the discharge line is expulsed into the pool. Following water clearing, the compressed air is released into the suppression pool and steam is injected and condensed, raising the suppression pool water temperature.

Q. Please describe the early Atomic Energy Commission criteria and review procedures for assuring containment design adequacy.

A. In the early days of nuclear power, from the late 1950's to the early 1960's, containment design requirements were described only in Preliminary or Final Hazard Summary Reports. Based on such reports, the containment design pressure and temperature were determined by hypothesizing the release of the entire reactor coolant inventory to the containment. As pointed out in the Dresden-1 Preliminary Hazard Summary Report, "the 'maximum credible accident' is conceived as an instantaneous complete severance of one of the bottom inlet lines to the reactor while the reactor is in a 'hot' standby condition. . . .The primary significance of a 'maximum credible accident' is that it determines the design of the reactor enclosure."' The term "maximum credible accident" was considered by the AEC and the industry at that time to be an occurrence which was on the verge of incredibility. It was used only to establish an upper bound for the containment design pressure. In other aspects, its occurrence was considered incredible by the AEC and the industry. The reason is that the reactor coolant system pipes are made of ductile material which is subjected to considerable material checks and inspections. Such a material might be expectd at worst to leak but not to undergo an instantaneous complete severance. In fact, the instanteous double-ended pipe break was considered so "incredible" at that time that no emergency water injection or core cooling system was produced to protect against such an eventuality. During this early stage of nuclear power develoment, the containment was also designed for seismic occurrence by simply applying static g-force on the structure and its equipment. No provisions were made for relief valve loads. In fact, in some of the earliest plants the relief valves were not piped to the suppression pool.

Q. Please describe the early tests to establish the feasibility of the pressure suppression containment and its design parameters.

A. Tests performed for Humboldt Bay in the late 1950's, along with additional data and evaluations, established that steam/water released by a loss-of-coolant accident could be condensed in a pool of cold water. Tests showed that adequate condensation could be obtained under simulated LOCA conditions with pool temperature reaching values of 163^{o} F. The primary emphasis of the Humboldt Bay tests was to establish containment design pressure under a variety of simulated loss-of-coolant accidents. Tests carried out in the early 1960's for Bodega Bay repeated the Humboldt Bay tests, except they employed 24-inch instead of 14-inch vent pipes. These tests confirmed that condensation was rapid and complete and they supported the analytical model developed previously.

During these early tests, minimal vibrations, pressure oscillations and water swell were noted, but these activities were either not relevant to the proposed pressure suppression design or they were simply too minor to affect test operations or its equipment. In fact, both the AEC and the ACRS evaluated the results of these early tests and later approved the pressure suppression concept based on this test data.

II. REVISIONS IN NRC CRITERIA AFFECTING CONTAINMENT DESIGN.

Q. Please describe the initial containment design criteria issued by the AEC.

A. The first regulatory seismic criteria came into being with the issuance of TID 7024 in 1963, and beginning in 1964 the AEC required seismic dynamic analyses of equipment and containment structures. These analyses consisted of applying earthquake ground accelerations to the structures and determining their responses. The dynamic responses so obtained for the structures were then applied to the equipment. During the 1964 to 1967 period, a little more credibility was given to the instantaneous rupture of the largest pipe in a BWR, by providing core spray systems which distributed water over the reactor fuel after the reactor vessel had been depressurized by the large postulated break. Also, pipe whip restraints were installed, but only on the reactor recirculation water system piping. The pressure suppression containment design requirements continued to deal only with assuring full condensation of the steam reaching the suppression pool and calculating the resulting history of containment pressure. There were still no requirements for relief valve loads because they were considered to be small compared to the maximum postulated seismic and LOCA loads, and no consideration was given at that time to combining relief valve, LOCA and maximum earthquake loads. Documentation of this containment design criteria status is confirmed by the guide for the organization and content of Safety Analysis Reports to be submitted by license applicants, prepared by the AEC Staff on June 30, 1966. This guide did not require Applicants to address hydrodynamic loads. Similarly, the Peach Bottom FSAR dated 8/31/70 states:

> "In order to establish a design basis for the pressure suppression containment with regard to pressure rating and steam condensing capability, the maximum rupture size of the reactor primary system must be defined. For this design, an instantaneous, circumferential rupture of one recirculation line, or equivalent failure of other equipment in the drywell has been selected as a basis for determining the maximum gross drywell pressure and the condensing capability of the pressure suppression system. The selection of an equipment failure of this size for the design-basis is entirely arbitrary, since it is considered that <u>circumferential failure of a recirculation pipe or reactor vessel failure of this magnitude is of such low probability as to be considered incredible</u>. Nevertheless, for design purposes these failure conditions have been selected to establish the containment parameters, but the failure modes and the magnitude of failures are assessed as being incredible." (Emphasis added).

The AEC reviewed this FSAR and accepted the characterization of the postulated break as "incredible." The AEC and the industry did not require the containments to design for other aspects of this rupture except for using the energy release from this postulated occurrence as a basis to establish containment design pressure.

Another example of the prevailing thinking at that time regarding the loss-of-coolant accident and its impact is reflected in a report of an Advisory Task Force on Power Reactor Emergency Cooling to the AEC, created in late 1966 (of which this writer was a member). One of the conclusions of this task force was that "We do not consider it necessary to assume that large and rapid failures will occur in any component or system which is designed, manufactured, inspected, protected against missiles, and operated in accordance with the requirements (equivalent to Section III of the ASME Code). . . .Such extreme protection could unnecessarily increase the system complexity and decrease the inherent reliability of the primary system. . ."

Q. Describe how the regulatory attitude changed in the 1967-1973 period.

A. Beginning in 1967, many new containment design bases were developed and enforced by regulators. In particular, much more conservative seismic and emergency core cooling criteria were imposed. First, Appendix A to 10 CFR 50 issued in 1971 provided an entire set of General Design Criteria (GDC). GDC 2 required that "the containment design bases shall reflect (1) appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area with sufficient margin for the limited accuracy, quantity and period of time in which the historical data have been accumulated; (2) appropriate combinations of the effects of normal and accident conditions with the effects of natural phenomena; and (3) the importance of the safety functions to be performed." While GDC 2 codified the need to combine seismic and loss-of-coolant conditions, the specific method of combining them was not defined except for stating that it should be appropriate. As pointed out below, the issue of load combinations was not settled for many years.

In addition to Appendix A, substantial conservatism was added to the seismic response spectra employed in Safety Analysis Reports. The response spectra utilized at Limerick are shown in Schedule 4, where they are also compared to those employed at the Susquehanna Plant. Also, Regulatory Guide 1.61 issued in 10/73 specified lower damping values and therefore higher seismic loads at nuclear plants. Moreover, in 1973 the NRC for the first time decided to combine three components of earthquake motion instead of two as previously prescribed.

Further, in 1973, Appendix A to 10CFR100 reiterated the need to design the containment structure for the Safe Shutdown Earthquake, or the earthquake of greatest magnitude expected at the power plant site. This Appendix sets the Operating Basis Earthquake (OBE) at one-half of the Safe Shutdown Earthquake (SSE). Originally, nuclear plant design was established from the occurrence of an earthquake of reasonable probability, i.e. the Operating Basis Earthquake (OBE), and there was no direct coupling with the low probability but theoretically conceivable maximum Safe Shutdown Earthquake. By specifying OBE at one-half of SSE, load combinations based upon OBE became quite conservative. This is important because the containment also is designed to sustain several load combinations involving OBE, and the design can be limited by such combinations when the OBE is increased arbitrarily.

Q. Were hydrodynamic loads related to LOCA or SRV a concern of industry or the AEC at this time?

A. No, they were not. All of the above-described new regulatory requirements were related to seismic concerns. Suppression pool temperature limits were written into the Technical Specifications of BWRs and operator actions were required when the temperatures reached specified levels. In Revision 1 of the Standard Review Plan, issued in 10/72, there is no mention of hydrodynamic loads for relief valves or loss-of-coolant accidents. Indeed, these hydrodynamic loads are first mentioned as a matter to be addressed in licensing in the Standard Review Plan Revision 2, i.e. the basic document employed by NRC Staff in their plant licensing reviews to determine the adequacy of design safety, issued in September 1975. The containment design requirements as to types of loads to be considered in this period of time are very similar to those prevailing up to 1967. As stated in NUREG-0487, "the original design of the Mark II containment system considered only the loads traditionally associated with design basis accidents. These included pressure and temperature loads associated with a loss-of-coolant accident (LOCA), seismic loads, dead loads, jet impingement loads, hydrostatic loads due to water in the suppression chamber, overload pressure test loads, and construction loads." Those loads were reviewed and approved repeatedly by the NRC as an acceptable basis of containment design and they satisfied the Standard Review Plan and Regulatory Guides published up to 1975.

Correspondence and analyses of the AEC at this time make no mention of a concern over hydrodynamic loads. In fact, in a September 20, 1972 memo to various AEC officials, Dr. Hanauer, then a technical advisor to the AEC's Executive Director for Operations, raised specific concerns about the pressure suppression design which did not include any mention of hydrodynamic loads. In addition, in a September 14, 1972 memo, Joseph H. Hendrie, then Deputy Director for Technical Review of the AEC's Directorate of Licensing and subsequently Chairman of the NRC, documented an evaluation of the GE Mark III Containment design with no mention of any hydrodynamic loads concern. This memo is attached as Schedule 5.' It is noteworthy that this memo reflects the culmination of an initial AEC review of the acceptability for employment in licensed reactors of the Mark III design. Clearly, if hydrodynamic loads were then perceived by the AEC as a significant safety concern, they would have been noted in this memorandum.

It should also be noted that numerous Mark I and II plants were licensed for construction or operation at this time in the U.S. and abroad by the AEC and foreign regulators after extensive safety evaluations.

III. <u>DESCRIPTION OF EVENTS WHICH CAUSED CONCERN OVER PRESSURE SUPPRESSION CONTAINMENT LOADS.</u>

Q. What initiated the concern over hydrodynamic loads associated with pressure suppression containments?

A. More and more attention focused on hydrodynamic loads as a direct result of performing new pressure suppression tests for the Mark III configuration and of relief valve actuation experience in operating power plants. The NRC officially raised the issue of hydrodynamic loads for the first time in two 50.54f letters dated April 18, 1975 and April 21, 1975. In the April 18, 1975 letter, the NRC referred to "results from recent developments associated with the large-scale BWR Mark III testing being conducted by General Electric Company. These tests indicated that suppression pool hydrodynamic loads during a loss-of-coolant (LOCA) should be considered in the detailed design" of the Mark II containment.

In the April 21, 1975 letter, the NRC also stated that "experience at several operating BWR plants has indicated that loads due to relief valve actuation may not have been fully considered in the structural design of the suppression chamber."

Q. Please describe the Mark III design development and its presentation to the NRC.

A. The Pressure Suppression Test Facility (PSTF) was built to test the horizontal vents of the Mark III containment design. During simulated loss-of-coolant tests at the PSTF in 1974, the pool surface was observed to rise to accommodate the air being injected into the pool through the horizontal vents. Targets of various sizes and geometries had been installed above the pool and the impact loads were found to be significant. These tests provided the first accurate and quantitative understanding of the pool swell mechanism. Subsequent to the period of vent clearing, the steam condensation in the Mark III design was observed to produce oscillating steam bubbles and loads. Additional tests performed at PSTF confirmed the early findings and they led to the NRC 50.54(f) letters issued in April 1975 to all utilities constructing Mark II containments.

Q. Please describe the BWR operating experience which contributed to the recognition of relief valve loads.

A. In April 1972, one of the relief valves failed to close after actuation at the Wuergassen BWR in Germany. This plant had no requirements for operators to take action when the suppression pool temperature reached prescribed levels. For that reason, while the operator was reducing power slowly, the pool temperature was allowed to exceed 160° F, at which time the condensation of steam being discharged through the relief valve into the pool became unstable, producing large condensation loads which vibrated the containment structure. The vibration was severe enough to separate the suppression pool liner from its attachments and water leaked into the drywell sump. The Wuergassen plant also employed straight-down pipes for the discharge of relief valves into the suppression pool, i.e. without ramshead diffusion devices as used in the United States. With such a configuration, the pool mixing is limited and the water temperature in the neighborhood of the discharge pipe reaches saturation temperature while most of the pool remains highly subcooled. Under these conditions, large steam bubbles form at the end of the relief valve pipe. When they leave the pipe, the bubbles may come into contact with highly subcooled water and they collapse rapidly to produce the severe vibrations observed at Wuergassen.

In July 1972, relief valve tests were performed at Muhleberg in Switzerland. Muhleberg utilizes straight-down pipes similar to those at Wuergassen. Suppression pool vibration was observed when the pool temperature was in excess of 140° F, at which point the test was terminated.

In contrast to Wuergassen and Muhleberg, the domestic plants at the time employed a ramshead discharge device. The ramshead consists of two elbows welded back to back; its discharge area is twice the area of a straight vent pipe and its water mixing capability is superior to that of the Wuergassen and Muhlenberg configurations. Several domestic plants had by 1975 experienced stuck-open relief valves, and at three of the plants suppression pool temperatures had reached from 146 to 165° F. In all three cases, however, due most probably to the ramshead and operator action, no unstable condensation or containment structure vibrations were observed. In every instance, the operators took action in accordance with the Technical Specifications which specify the following steps in the event of elevated suppression pool temperatures:

- With the reactor at power, the operator shall scram the reactor when the suppression pool temperature exceeds 110^{o} F.

- When the suppression pool temperature reaches 120^{o} F following an isolation/scram, the operator shall depressurize the primary system to less than 200 psig at normal cooldown rate.

It should be noted that the testing for Humboldt Bay and Bodega Bay, as well as later tests, had consistently indicated that pressure suppression containments would retain adequate quenching capability with suppression pool temperatures up to 160^{o}, assuming technical specifications were followed. Thus, the above operating procedures provided a significant margin of safety against occurrence of the difficulties experienced at Wuergassen and Muhleberg. In fact, the limiting suppression pool temperature conditions combined with the improved diffusion capability of the ramshead have resulted in no significant instances of condensation instability or containment structure vibration at domestic plants during normal operations which could be definitively attributed to the Wuergassen phenomenon.

In spite of this entirely satisfactory performance, the NRC Staff conservatively recommended in the mid-to-late 1970's that all BWR plants be equipped with more sophisticated quencher devices to further increase their pool temperature margin. Quenchers consist of two or more lengths of perforated pipe sections which are attached to the discharge pipe. Plants have utilized T and X types of quenchers. They each help to stabilize the condensation process as well as to reduce the hydrodynamic loads associated with safety relief valve actuation.

IV. DESCRIPTION OF MARK II HYDRODYNAMIC LOAD DEFINITION AND RESOLUTION PROGRAM.

Q. What types of LOCA hydrodynamic loads were discovered, characterized and resolved by design changes in 1975 and later?

A. Three basic types of LOCA hydrodynamic loads were identified: water jets associated with vent clearing, pool swell, and condensation loads. Shortly after a loss-of-coolant accident, water in the vents is forced out into the suppression pool and it produces jet loads. Following this water clearing phase, drywell gases are injected into the suppression pool. Gas bubbles are formed and they cause the pool of water to oscillate and swell, which produces another set of loads. Following this phase, condensation of the steam produces a loading on the containment structures and attached piping. The NRC letters of April 1975 led to a substantial development program which required thousands of engineers, several large-scale new test facilities, tests in several power plants, and over seven years to complete.

Q. What new tests and test facilities were required to understand and define the effects and design solutions for these LOCA loads?

A. The primary data needed to permit definition and resolution of Mark II hydrodynamic loads was obtained at the Temporary Tall Tank Test (4T) Facility located in San Jose, California, which was put into operation late in 1975 specifically for use in the investigation program initiated as the result of the NRC letters. The original design of this facility utilized a drywell not located above the wetwell and a downcomer not prototypical in terms of length. The original configuration was intended principally to obtain pool swell data, this being the hydrodynamic load perceived as the principal safety concern at this time. In 1975, the forces and effects associated with the loads ultimately determined to be more significant, i.e. condensation oscillations and chugging, were not appreciated. A large number of pool swell tests were performed and an analytical model was developed which gave conservative predictions of the experimental results. In the course of performing these experiments, the effect and forces of the additional loads described above were first observed in a Mark II containment. Condensation oscillation loads occur early in the LOCA while drywell air is still mixed with the steam. Later in the LOCA, the condensation is characterized by the growth and rapid collapse of steam bubbles at the downcomer vent exit. After the bubbles collapse, water enters the vent, and after a short period of time to build pressure within the vent and push the water out, a new bubble is formed, and it collapses to allow water to reenter the vent. This periodic off-on mode of condensation has been labeled chugging. The 4T tests were the first to demonstrate significant forces associated with chugging. These initial tests performed at the 4T facility were used to develop the first set of bounding loads for the Mark II containments.

Q. Was any additional test data employed to define these loads and develop appropriate design resolutions?

A. Yes. Testing was conducted by domestic and foreign industry and regulators to resolve this phenomenon and their results were employed in the U.S. program. For example, tests were performed in Germany at the GKM facility with a single downcomer located within a cylindrical tank to measure lateral loads for vent configurations employed in that country. The tests revealed that the maximum lateral loads occur at the later stages of a loss-of-coolant accident. These measured loads were employed in 1975 in the U.S. by the AEC to prescribe for the first time lateral loads for Mark II vents.

Additional tests were conducted at Creare in New Hampsire. These tests were subscale tests whose purpose was to compare single and multivent loads. The tests were carried out from 1976 to 1980. While the Creare tests exhibited the same characteristics as the 4T tests, a good extrapolation of the condensation loads from small-scale to full-scale tests could not be developed.

Also, additional tests were conducted at the 4T facility in the U.S. In these new tests, completed in 1979-1980, the drywell was located above the wetwell and the vent pipe length was reduced to be prototypical of the Mark II design. The new series of experiments was used to generate a new set of bounding loads for Mark II containments.

In 1977, a program was initiated in Japan to measure hydrodynamic loads in Mark II containments. A facility was built at JAERI using 7 downcomer vents in a 20° annular section of the suppression pool. The JAERI tests were full scale and their results started to become available during 1979. The JAERI findings were employed to further refine the condensation loads and they were heavily relied upon by the NRC to issue their final acceptance criteria in August 1981.

Q. Please describe the design solutions developed to resolve the relief valve hydrodynamic load concerns.

A. Shortly after the Wuergassen incident, small-scale tests of quenchers were performed at the Manheim Power Station (GKM) in Germany. The experience revealed that the quencher benefits depend upon the hole pattern employed in the perforated pipe attached to the discharge pipe. After the hole pattern was optimized at reduced scale, practically full-scale models of X-quenchers were tested and they showed that smooth steam condensation could be obtained up to the highest attempted pool temperatures of 203° F to 214° F. In 1977, similar tests at increased pool temperatures were performed on full-scale T-quenchers at the Karlstein test facility in Germany and stable condensation was obtained up to the highest tested temperature of 196° F. Extensive measurements were carried out on full-scale models at this facility, and a comprehensive set of data was developed for variation with reactor pressure, discharge line length, and pool temperature. Subsequent startup tests performed at Mark II plants demonstrated the adequacy of the load data and of the acceptance criteria derived from this data.

A variety of safety relief valve quenchers have also been tested at nuclear power plants. In 1976, the X-quenchers performed well at the Brunsbuttel Nuclear Power Plant (KKB) in Germany where the suppression pool was allowed to go up to 150-170° F. In late 1977 and early 1978, two series of tests were performed at the Monticello Plant, with the first test using the original ramshead discharge configuration and the second test using the quencher attached to the ramshead. These experiments showed that by operating the containment pool cooling system, the pool temperature maldistribution could be reduced significantly. Similar tests were conducted at the Peach Bottom Generating Station, and they produced comparable results.

Finally, full-scale load quencher tests were performed at several power plants, including Tokai-2 in Japan in 1978, Caorso in Italy in 1978-1979, and Kuosheng in Taiwan in 1981. Of particular interest is the finding that the measured impact on equipment at Caorso was considerably less than predicted. Similarly, the air clearing loads recorded at Kuosheng were about one half the anticipated values.

Q. Please describe the NRC's role in this Mark II program.

A. The NRC went through an iterative process to determine final Mark II load definitions. The following are the major NRC requirements as they were issued:

- NUREG-0487, issued in October 1978, provides a methodology acceptable to the NRC for evaluating and assuring design resolution of both loss-of-coolant and relief valve loads. It was aimed at the lead Mark II facilities. NUREG-0487 states that it "includes bounding load specifications for certain loads. These loads were derived from tests and analyses completed in the Lead Plant Program. This assures that conservative loads are used in the assessments of the lead plants."

- In Supplement 1 to NUREG-0487, published in September 1980, the NRC reviewed alternate pool dynamic loads, accepted some as submitted and approved others only after modification.

- Supplement 2 to NUREG-0487, was issued in February 1981 because large scale tests conducted in 1979 revealed that the original methods of NUREG-0487 did not bound all the load amplitudes at frequencies observed in the new steam condensation tests.

- NUREG-0808, published in August 1981, provides a final set of LOCA-related suppression pool hydrodynamic loads for Mark II containments. The NRC required all Mark II designs to be reviewed against this last set of loads.

- NUREG-0783, released in November 1981, specifies suppression pool temperature limits for BWR containments to avoid excessive condensation loads from relief valve actuations.

- NUREG-0802, issued in October 1982, provides NRC evaluation of safety relief valve loads when the valves are equipped with quenchers.

Q. Please further define the actions taken by the NRC which led to the above requirements.

A. As one can surmise from the preceding description, the NRC required a substantial amount of testing, evaluation, retesting and reevaluation before all of its concerns were satisfied. Early testing and evaluations simply served to sharpen and particularize NRC concerns, which were then resolved by more focused tests and analysis. The NRC insistence upon bounding test results led to continued escalation in design requirements throughout the program, and to the need to iteratively perform additional tests and to develop additional load data. New dynamic analysis methods had to be generated to take into account the measured hydrodynamic loads.

Also, the specific process of defining and resolving Mark II hydrodynamic loads was rendered substantially more difficult and time consuming because the NRC at this time was increasing the severity of seismic and other load combinations required to be employed in containment design analysis. As described above, combining of such loads as a basis for evaluating the safety of containment design was first required by General Design Criteria 2. However, no specific combination was mandated, it merely being required that the combination used be "appropriate". During the mid and late-1970s, the combination that was viewed as "appropriate" was constantly increased. For example, a letter to the NRC dated November 25, 1975 lists the loads being considered at the Shoreham Plant and how they are to be combined. A simultaneous combination of loads from the Safe Shutdown Earthquake (SSE), the largest loss-of-coolant accident (LOCA), and the relief valve actuation is not included. However, subsequently the NRC insisted that such a combination be reflected in containment design.

During this period of emphasis upon hydrodynamic loads, there were also other escalations in containment loads. For example, Regulatory Guide (1.122) issued in July 1976 and revised in February 1978 stipulated that the spectra used for piping design should be broadened by plus or minus 15 percent. Also, in 1975, it became necessary to consider asymmetrical transient pressures resulting from loss-of-coolant accidents. These asymmetrical requirements particularly impacted the reactor vessel, its internals, supports, and immediately connected piping.

Q. Dr. Levy, please summarize the significance of the data you have provided on this testing and evaluation program.

A. The preceding discussion gives a good picture of the multitude of programs which were carried out to understand and to develop design resolutions for the hydrodynamic loads for Mark II pressure suppression containments. The number of facilities, nuclear power plants, and engineering efforts involved were enormous. Some of the measurements were extremely difficult and some of the tests had to be repeated as new insight was acquired (e.g. the 4T tests). The decision to bound data and the need to present it in the form of load versus frequency increased the complexity and magnitude of the program. A total of about seven years was required from recognition of the new loading concerns to their solutions. Clearly, the understanding and the required knowledge were not available in the 1960's and early 1970s. They had to be developed painstakingly in an extensive iterative process between the industry and the AEC/NRC.

Q. What were the final results of the NRC's "ratcheting" of containment design load requirements?

A. A quantitative picture of the escalation of loads in BWRs with time has been developed by J. D. Stevenson, in a Report to the University of California Radiation Laboratory at Livermore (October, 1980), and his results are reproduced in Schedule 6. As there shown, between 1968 and 1984, total containment design loads have increased by a factor of over 2.5, and the seismic load increase accounted for slightly less than half of the increase. This increase in containment design loads can be traced to three principal factors: (1) the NRC decision in the late 1960's to give credibility to the instantaneous double-ended rupture of the largest pipe connected to the reactor vessel; (2) the NRC bounding approach to the hydrodynamic loads observed in tests described above; and (3) the conservative combining of loads.

Q. Dr. Levy, what is the significance of this data to the resolution of containment design concerns at Limerick?

A. This data indicates that these concerns were not solely related to Mark II hydrodynamic loads, and further that the resolution of the Mark II loads problem was rendered substantially more difficult by revisions in NRC seismic load and other criteria or safety evaluation methods. These latter factors are entirely unrelated to any alleged "technical error" in the original Mark II design. Thus, the time and cost required to resolve Mark II containment design concerns cannot be assessed as being solely attributable to the hydrodynamic loads concern.

Q. Have there been any recent and significant developments in NRC views respecting appropriate BWR containment design loads?

A. Yes, there have. Most recently, the NRC has indicated concern that its current design load requirements are unduly severe and thus greater than needed to assure safe plant operation. An NRC Piping Review Committee has been formed to carry out a comprehensive review of these requirements (including regulations, regulatory guides, standard review plan acceptance criteria, and Staff positions delineated in various NUREG reports) in the area of nuclear power plant piping. The Committee's recommendations issued in April 1985, include the following points:

> "The first priority item would relax the loss-of-coolant criteria and apply leak-before-break criteria instead." (In other words, the instantaneous rupture of pipes is incredible.)
>
> "Changes in seismic damping values, the second priority item, have been accepted on a case-by-case basis. Broader implementation of these changes could substantially reduce the excessive number of piping supports, particularly snubbers."
>
> "The third priority item, a change in operating basis earthquake (OBE) accelerations, would have a major impact on the design of new plants and extend well beyond piping consideration."
>
> "We believe it is appropriate to decouple the loss-of-coolant (LOCA) from seismic events; the evidence confirms such a position."

The NRC is obviously questioning whether current load requirements are too conservative. If all of the above recommendations are adopted, the containment loads would decrease sharply toward the level originally prescribed in the early 1960's.

Q. Dr. Levy, has OCA witness Hanauer accurately described the Browns Ferry tests?

A. No, his description is substantially inaccurate. It is true that on November 8, 1973, significant noise was heard from the Mark I torus at Browns Ferry-1 after the relief valves were opened. It was discovered, however, that the discharge pipe of one relief valve had vibrated against the floor grating and its clearance was increased to eliminate this problem. Instruments were also installed on the torus and excessive movement of the torus header as well as high deflections on the torus were measured in subsequent tests. Thereafter, several torus support saddles were found not to be in full contact with their support pads. Temporary shims were employed while the plant was running and jacks were obtained to preload the support cradles during the next plant scheduled outage. Several relief valves were actuated with the installed shims and the measured movement and deflections were found to be relatively the same. Next, the torus ring header was modified to prevent the vertical movement of the header relative to the support and the torus support saddles were jacked. The movement and deflections decreased sharply from the earlier tests especially after "shakedown" or "settlement" of the torus.

It is important to note that the vibrations at Browns Ferry-1 were produced by air clearing loads and not by unstable condensation or high temperature as implied by Dr. Hanauer. Further, a total of 33 single and multiple relief valve actuations were carried out without impacting the integrity of the torus. Also, the noises and vibration experienced were in large measure the result of problems unrelated to the adequacy of containment design, i.e. the improper seating of the support saddles. The tests were at no time stopped due to safety concerns.

Q. Please respond to Dr. Hanauer's statement that the original Mark II design posed significant safety risks.

A. Several times during his testimony, Dr. Hanauer implies that the safety of the involved plants was in serious jeopardy. In fact, although the containment design margins were reduced, the plants were always safe for several reasons.

Dr. Hanauer cited the Wuergassen relief valve incident of April 1972 and the Browns Ferry startup relief valve tests of late 1973 to assert that "large forces which were potentially destructive to the suppression chamber" were produced. In the case of the Wuergassen incident, he fails to point out that U.S. plants were equipped with a different pipe exit configuration (ramshead versus the straight pipe configuration used at Wuergassen). As pointed out in NUREG-0783, "experimental results show that the ramshead device provides a much better steam condensation process than the straight pipe." Furthermore, Dr. Hanauer fails to mention the limiting conditions for operating a BWR plant with a pressure-suppression containment structure, as described above. The Wuergassen events would not have happened if such operating procedure temperature limits had been enforced and if a different discharge configuration had been utilized.

In the case of the Browns Ferry plant, the relief valve tests were initiated after it was noted that one relief valve discharge pipe had vibrated against the floor grating. In contrast to witness Hanauer's recounting and as explained above, these forces were not produced due to condensation at increased pool temperatures but rather due to air clearing loads. Finally, Dr. Hanauer's contention about the safety implications of relief valve loads contradicts NUREG-0474 which states that:

> "For the operating Mark I plants we have determined that there is sufficient fatigue margin to permit continued plant operation while a new discharge device is developed, or until the plant's capability to withstand the loadings from the existing discharge device for the anticipated (40 year) life of the facility can be demonstrated."

With respect to the containment hydrodynamic loads, it is important to point out that the design margins were reduced only for extremely rare accidents, i.e. the simultaneous occurrence of a Safe Shutdown Earthquake and of a double-ended instantaneous large pipe break. It is especially illuminating to note that in NUREG-0408, Mark I Containment Short Range Program, the NRC staff concluded that "licensed Mark I BWR facilities can continue to operate safely, without undue risk to the health and safety of the public, during an interim period of approximately two years while a methodical comprehensive long range program is conducted." As described by PECO witness Vollmer, the structural integrity of the BWR Mark II containment is far stronger than that of the BWR Mark I.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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WORK EXPERIENCE:

1950 - 1953	Research Engineer, University of California, Berkeley, Calif. Conducted boundary layer studies of heat transfer in high speed flight.
1953 - 1954	Engineer Analyst, Knolls Atomic Power Laboratory, Schenectady, New York. Worked with steam boilers andsuperheaters.
1954 - 1956	Supervisor, Atomic Power Equipment Department, General Electric Company, San Jose, California. Responsible for the design, safeguard analysis, and development of small atomic power plants and test reactors. 15 employees.
1956 - 1959	Advance Nuclear Specialist, Atomic Power Equipment Department, General Electric Company, San Jose, California. Worked on advanced reactor concepts such as fast oxide breeders.
1959 - 1966	Manager, Heat Transfer and Reactor Projects, Atomic Power Equipment Department, General Electric Company, San Jose, Calif. Responsible for heat transfer and fluid flow development in boiling water reactors. 30 employees.
1966 - 1968	Manager, Systems Engineering, Atomic Power Equipment Department, General Electric Company, San Jose, California. Responsible for conceiving and defining nuclear power plant systems for all requisition and proposal plants and all near-term improvements in nuclear power plant systems. 150 employees.
1968 - 1971	Manager, Design Engineer, Atomic Power Equipment Department, General Electric Company, San Jose, California. Responsible for design engineering of all nuclear systems being offered by the General Electric Company and for all recent and future project management functions associated with domestic nuclear systems. 630 employees.
1971 - 1973	General Manager, Nuclear Fuel Department, General Electric Company, San Jose, California. Responsible for the design, development, and manufacture of nuclear fuels for light water reactor systems and for reprocessing of irradiated fuel. Approximately 1600 employees.

1973 - 1975	General Manager, Boiling Water Reactor Systems Department, General Electric Company, San Jose, California. Responsible for the design and development of nuclear systems including fuel. Also responsible for the manufacturing of control and instrumentation. Approximately 2300 employees.
1975 - Oct.1977	General Manager, Boiling Water Reactor Operations, General Electric Company, San Jose, California. Responsible for the engineering and manufacturing of all boiling water reactors. Approximately 5,000 employees. Resigned to form own independent consulting firm.
1977 - Present	President, S. LEVY, INCORPORATED, Engineering/Management Consulting Firm. Involved in the following types of work: Member of the Industry Advisory Board during the TMI-2 accident Consultant to the Kemeny Commission Staff Consultant to Brookhaven National Laboratory Consultant to Electric Power Research Institute Consultant to many United States utilities, including being a member of two independent safety review boards (GPU and Detroit Edison) Member of Nuclear Oversight Committee for Public Service Electric and Gas Consultant to the NRC on their Advanced Code Review Committee Consultant to World Bank/UNDP on nuclear safety in Korea Member of four PRA Review Boards Springer Professor, University of California, Berkeley Adjunct Professor of Engineering, University of California at Los Angeles Director, Iowa Electric

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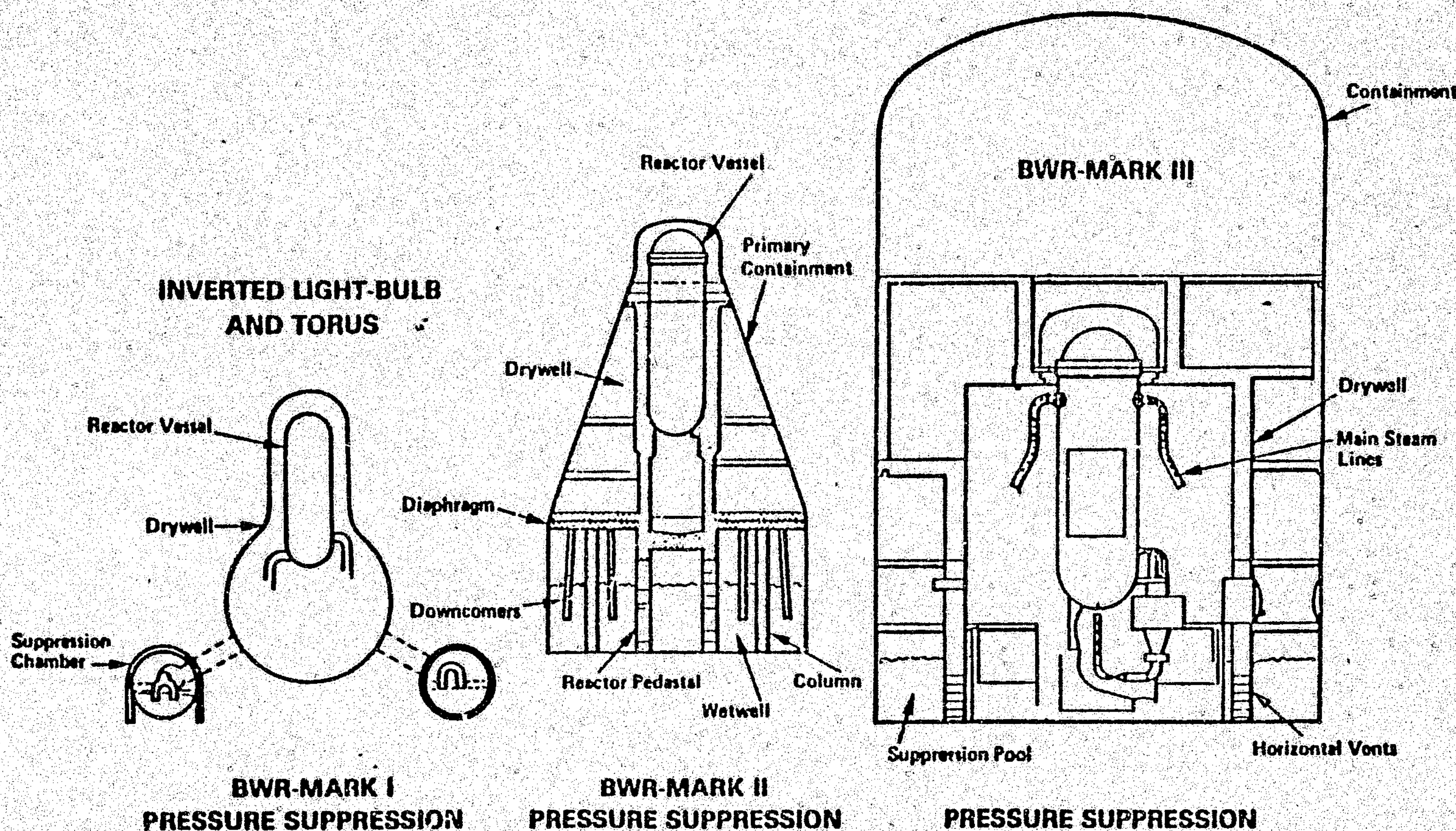
INVERTED LIGHT-BULB
AND TORUS
Reactor Vessel
Drywell
Suppression Chamber
BWR-MARK I
PRESSURE SUPPRESSION
Reactor Vessel
Primary Containment
Drywell
Diaphragm
Downcomers
Reactor Pedestal
Wetwell
Column
BWR-MARK II
PRESSURE SUPPRESSION
Containment
BWR-MARK III
Drywell
Main Steam Lines
Suppression Pool
Horizontal Vents
PRESSURE SUPPRESSION

Figure 1

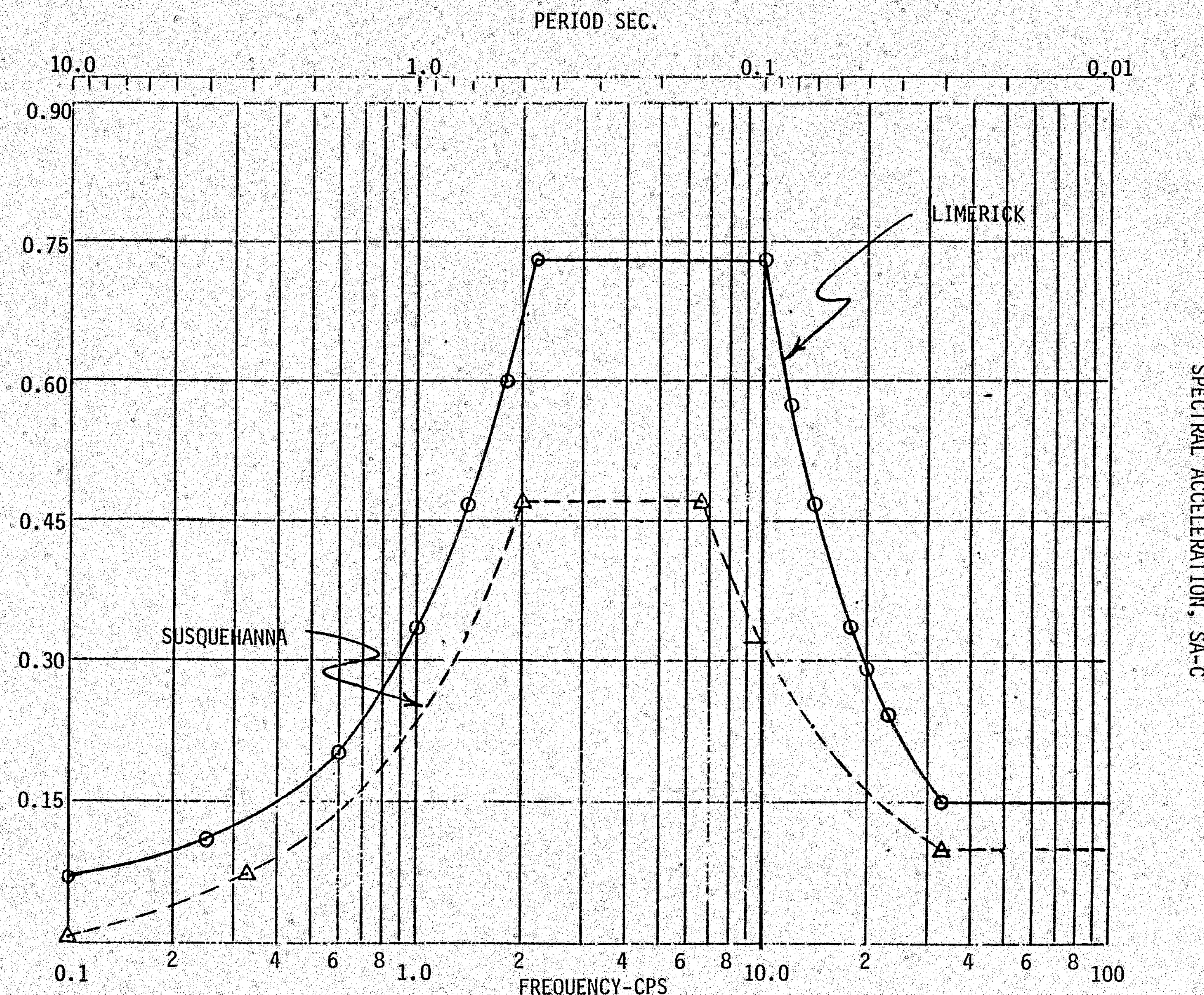

Figure 2. Comparison of Susquehanna (SSES) & Limerick (LGS) Design Spectra (SSE) at 0.5% Damping

Schedule 4

SEP 14 1972

Roger S. Boyd, Assistant Director for BWR's, L

GE MARK III CONTAINMENT AND BWR/6 REACTOR

We have completed our review of the GE topical reports relating to the proposed Mark III containment concept. The pertinent memoranda from Tedesco, Knuth, and Denton are enclosed. We have had several meetings with the GE people to clarify various points we have raised.

The Mark III containment appears to be a feasible scheme, subject to the comments made in the enclosures. It is proposed by GE as an answer to the criticisms of previous BWR containments by architect-engineers that construction was difficult and expensive. We have no objection to new designs proposed for economic reasons, asking only that applicable criteria and standards be used and that previously established safety margins not be compromised.

The conceptual nature of the material presented to us thus far on the Mark III containment leaves many details unsettled and raises many questions. A number of these are outlined in Tedesco's memorandum of July 15, 1972. Our opinion is that questions regarding most of these details can be resolved in our review of the first application incorporating the Mark III containment. Several more serious issues remain, however, and these are noted below, in order of increasing importance.

First, possible by-pass leakage paths from the drywell to the outer containment are not considered in the present reports. The control of such by-pass paths will be important to assure that the design pressure of the containment is not exceeded for postulated design basis accidents. The control of by-pass leakage in Mark III would be complicated (as it is in the PWR ice-condenser containments) if it is necessary to include provisions for controlled recirculation of the containment atmosphere at substantial flow rates after the initial primary blowdown in order to dilute hydrogen produced by metal-water reactions and radiolytic decomposition. The recirculation flow rates required are a function primarily of the metal-water reaction assumptions (see point three, below), but even the radiolytic hydrogen component by itself requires an appreciable vent area between inner and outer containment volumes. Design features provided for recirculation might result in a significant potential for by-pass leakage if they are not handled carefully.

R-37

Second, the tests of the Mark III pressure suppression design carried out to date have been at a very small scale (about 1/2000) and have lacked geometrical similitude to the Mark III configuration. No further tests are proposed by GE until they have received the results of our current review. The Mark III concept is similar to the previous BWR pressure suppression concept in that steam is passed through cool water to condense it. There the similarity stops. A few years ago, in connection with our review of the proposed "over-under" geometry for pressure suppression containment, GE and the applicants involved made the point that the downcomer minimum spacing, submergence, size, and flow rate for the "over-under" design were all within the range of test data previously obtained in the Humboldt Bay tests, so that no extrapolations of pressure suppression performance were required. This careful approach in justifying a new geometry seems to be missing in the Mark III proposal. We will require further model tests of the pressure suppression capability of the Mark III concept, with appropriate geometrical similitude and at substantially larger scale than 1/2000.

Third, GE requests relief from the provisions of Safety Guides 3 and 7, and is adamant on these points thus far. Their argument is based on the claimed superiority of the BWR/6 core with the Zimmer-class ECCS in holding calculated cladding temperatures and metal-water reaction in postulated LOCA events to lower values than any other LWR design. The detailed thermal-hydraulic performance of the BWR/6 core has not been presented or reviewed as yet, but we are willing to concede that with the lower linear power densities proposed for the BWR/6 fuel the LOCA temperatures and amount of metal-water reaction should indeed be lower than for previous designs. These are certainly desirable features in the BWR/6 design, but these features are not necessarily compelling reasons to abandon the present philosophy for the design basis of containments.

We have always separated the design bases for ECCS and containment and have required the containment, as the last-ditch protection against accidents, to be designed to withstand a more degraded condition of the reactor than the ECCS design basis permits. We have in the past felt that this "overlap" in protection provides an appropriate and prudent safety margin against unpredicted events in the course of accidents. Both Safety Guides 3 and 7 are drawn to preserve this safety margin. Both guides were the outcome of careful, detailed, and at times painful consideration of all the issues involved.

The question before us, with Mark III, is whether our present state of knowledge of ECCS performance in design basis accidents has sufficiently improved in the last two years to change our previous conclusion that there is a need to maintain a substantial margin between the ECCS and containment design bases, and in effect to decouple the containment design basis from any detailed consideration of ECCS performance. And further, should the answer be affirmative, whether the BWR/6 ECCS performance is sufficiently improved to justify designing the Mark III containment to be consistent with that performance.

We conclude, on balance, that we need to maintain the safety margin inherent in the present separation of ECCS and containment design bases, and that the provisions of Safety Guides 3 and 7 as they now stand should apply to the Mark III containment. Accordingly, we will require that the Mark III design include provisions for containment atmosphere recirculation and hydrogen recombiner systems and that the fission product release assumptions of Safety Guide 3 be used as a design basis for leakage rate and containment atmosphere clean-up systems. We believe these provisions can be made in the Mark III containment, just as they are being made in the similarly-arranged and sized ice-condenser containments. The recirculation system connections between inner and outer volumes will require careful attention to control of by-pass paths, as noted in point one, above, but we believe this can be accomplished satisfactorily. The design pressure margin over maximum calculated accident condition pressure should be the same as for previous pressure suppression schemes.

This review of our basis for Safety Guides 3 and 7 has been a useful exercise for us and we believe that we should reopen the questions raised by GE at an appropriate time in the not-too-distant future. My own guess would be that one to two years would be enough time for us to have digested the results of the current ECCS performance reviews and to have gained further useful operating experience from the plants now coming on line. Past experience suggests that we will gain many interesting and unexpected insights into the behavior of plant equipment, including ECCS, from the startup of the new plants. I do not think that Safety Guides 3 and 7 should, or will, stand in their present form for the indefinite future but I am convinced that a change at the present time is not justified.

Original Signed by
J. M. Hendrie
Joseph M. Hendrie, Deputy Director
For Technical Review
Directorate of Licensing

Enclosures:
1. Memo Knuth to Boyd, 9/5/72
2. Memo Tedesco to Boyd, 7/18/72
3. Memo Denton to Boyd, 8/23/72

L:TR

X JMHendrie:eaj
9/14/72

cc: See attached

Table 1

HISTORICAL SUMMARY OF TYPICAL LOSS-OF-COOLANT ACCIDENT (LOCA) AND SAFE SHUTDOWN EARTHQUAKE (SSE) (0.2-g) EQUIVALENT STATIC LOADS ON BWR REACTOR COOLANT SYSTEM COMPONENTS

Load/period (Thousand Pounds)

Item	Nominal Component Weight	LOCA 1965-1968	SSE 1965-1968	LOCA 1968-1975	SSE 1968-1973	LOCA 1975-pres.	SSE 1973-pres.
Reactor vessel	4000	800	1600	1600	3200	7000	6000
Reactor internals	2700	400	1600	800	3200	3500	4000
Recirculation pump*	180	---	100	---	300	540	540

* LOCA pipe reaction loads on pump in broken loop not considered.

PECO STATEMENT NO. 34A

P.G. 3-14-86 Hrg R-850152

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY
DOCKET NO. R-850152

SUR-SURREBUTTAL TESTIMONY

OF

SALOMON LEVY

MARK II CONTAINMENT ISSUES

March 13, 1986

SUR-SURREBUTTAL TESTIMONY OF SALOMON LEVY

Q. Please state your name and business address for the record.

A. My name is Salomon Levy. My business address is 3425 S. Bascom Avenue, Campbell, California, 95008.

Q. Are you the same Salomon Levy who gave rebuttal testimony in this docket?

A. Yes, I am. My rebuttal testimony on the Mark II Containment Issues is identified as PECo Statement No. 34.

Q. What is the purpose of your sur-surrebuttal testimony?

A. In my sur-surrebuttal testimony I respond to the latest allegations made by OCA Witness Hanauer in his surrebuttal testimony regarding the alleged Mark II design error. Prior to beginning that response, however, I believe it important to point out two significant concessions made by Dr. Hanauer from his prior testimony:

- Dr. Hanauer admits that he originally overstated the safety significance of the Mark II hydrodynamic loads and that his position is now only that "the design margins were reduced by the additional forces" and that "in the end, major design modifications were not required in the Mark II containment structures" (page 35).
- Dr. Hanauer admits that he failed to recognize changes in the NRC requirements related to Mark II containments including "additional requirements relative to safety/relief valve operation, including postulation of multiple simultaneous valve openings and more severe design basis combinations of loads... a general tightening up of NRC requirements for more detailed analysis, greater reliance on experimental verification, and more conservative acceptance criteria" (pages 35 and 36).

Q. Dr. Levy, what are Dr. Hanauer's allegations to which you will be responding?

A. First, Dr. Hanauer employs material contained in the Humboldt Bay, Final Hazards Summary Report issued in September 1961 to assert that two of the phenomena which were investigated many years later were observed in pre-1961 tests. Second, he utilizes a complaint filed by the owners of the Zimmer plant to support his contentions.

Q. Dr. Levy, what is your response to Dr. Hanauer's allegation respecting information provided in the Humboldt Bay Final Hazards Summary Report?

A. It is essential to recognize that the information contained in the Humboldt Bay Final Hazards Summary Report was available to the public, numerous architect engineers, AEC/ACRS and foreign regulators and that none of them identified hydrodynamic phenomena deserving further investigation at that time. Moreover, the material provided in the Humboldt Bay Final Hazards Summary Report was given very wide distribution by being published in ASME Papers 59-A-215 (provided in IR-OCA-28-11) and 61-WA-222 (provided in IR-OCA-28-18) printed in 1959 and 1961, respectively.

Q. Why are the hydrodynamic effects which Dr. Hanauer asserts were apparent from the tests reported to the AEC in the Humboldt Bay Hazards Report not significant?

A. These alleged effects arise from observations made in two Pacific Gas & Electric test facilities called the Condensing Tank Facility and the Humboldt Bay Facility. As I will explain in greater detail below, these tests did not identify any hydrodynamic loads perceived to be relevant to containment design for the following reasons:

- The Condensing Tank Facility tests were performed with a steady flow of steam and did not simulate the transient steam flow conditions of a LOCA. Also, the test facility did not reproduce the configuration of pressure suppression designs or provide such specific design features as vacuum breakers. This important difference between the Condensing Tank Facility and the Humboldt Bay prototype facility is supported by the lack of observation of vibrations in the prototype facilities up to 163°F, in contrast to their occurrence at 120-130°F in the Condensing Tank Facility.

- The tests were performed in order to find the limits of effective suppression pool steam condensation and were carried out under conditions not permitted to occur at nuclear power plants. Dr. Hanauer fails to quote other sections of the Humboldt Bay Hazards Report which explain that pressure suppression containments are restricted to operation with suppression pool temperature conditions well below that capable of producing the observed vibrations.

- The hydrodynamic effects observed in the Condensing Tank Facility are different from the LOCA condensation oscillation observed in the 4T facility about 15 years later. The Condensing Tank Facility vibrations are produced by an unstable mode of condensation produced by high water temperatures near the vent exit, while the 4T condensation oscillations are produced at low water temperatures and are set mostly by the vent length and its response to sound waves traveling through it.

- The observed upward water movement in the Humboldt Bay tests looked more like a "froth" (mixture of water and air) rather than an unbroken large water ligament being uplifted over the entire pool, which was the pool swell phenomenon of later concern in the Mark II design in the mid-1970s.

- The hydrodynamic loads associated with an unbroken water ligament were measured only in 1974 and 1975. Furthermore, these loads are several times those associated with a froth mixture. Mark III pool swell tests performed in the late 1970s have shown that froth dynamic loads are six to seven times less in magnitude than those measured for solid water.

Thus, the Humboldt Bay hydrodynamic effects alleged by Dr. Hanauer in his surrebuttal testimony are different and less significant than those which generated the extensive Mark II load evaluation program in 1975.

Q. Dr. Levy, have you provided additional information to the Office of Consumer Advocate respecting what, if any, hydrodynamic effects were observed in GE testing of the pressure suppression concept in the 1950s and 1960s?

A. Yes, I have. Employing the Zimmer Complaint allegations, the Consumer Advocate asked me a number of questions respecting the presence of hydrodynamic phenomena during these tests. I have compiled those of my answers which are relevant to this subject in PECO Exhibit SL-1 which accompanies my testimony.

Q. Employing your PECO Exhibit SL-1 as a reference, would you please describe the testing program which Pacific Gas & Electric and GE engaged in to evaluate the pressure-suppression concept, pointing out the significance or insignificance of any hydrodynamic phenomenon observed during those tests?

A. A systematic and extensive test and analysis program was employed to confirm the original Humboldt Bay pressure suppression containment design. It consisted of several steps:

1. <u>Preliminary small scale tests at Vallecitos to verify that condensation of steam will occur under a variety of conditions</u>. These tests were performed at steady steam flow rate conditions and the quenching tank was not

configured to match any pressure suppression containment design; they therefore were not capable of providing meaningful hydrodynamic load data for containment designs. The Vallecitos tests covered a wide range of pool temperatures and utilized vents of very small diameter, two inches or below. Steam bubble formation at the end of the vent as well as intermittent vent condensation were observed during the tests, but the corresponding measured pressure transients during such observations were small. The Vallecitos tests showed that the pressure suppression concept was feasible and they led to the recommendation that additional tests at increased scale be performed.

2. <u>Tests at the Condensing Facility located at the Moss Landing Power Plant of Pacific Gas and Electric Company.</u> This facility was built and operated by Pacific Gas and Electric Company. The condensing tank was 20 feet in diameter and 24 feet high. It utilized single vertical and horizontal vents varying from 4 to 14 inches in diameter. A series of tests also was carried out to study the interaction of three vertical vents discharging into a simulated containment compartment. Once again, these were steady flow rate tests and were not configured to match the geometrics of pressure suppression containment designs. Steam flows of 10 to 93 thousand pounds per hour were used and the tank water temperature varied from 50° to 150° F. Complete steam condensation was obtained in every case as long as the pipes were submerged a few inches into the water. Tank vibrations were observed at high pool temperatures. They started at 120 to 130° F and became severe at increased pool temperatures. The Condensing Tank Facility tests showed that steam condensation was assured as long as the

pool temperature was kept below 120-130° F. and restrictions were imposed on pressure suppressions designs to avoid such temperatures.

3. Tests at the GE Transient Facility in San Jose. The purpose of these tests was to obtain pressure transient data during a simulated LOCA in a pressure suppression facility. The volumetric scale of the Transient Facility was one thousandth that of the Transient Humboldt Bay design. It was not identical to the Humboldt Bay configuration. A variety of LOCA break sizes and vent depth submergences were evaluated. The tests showed that condensation was complete and that the measured pressures agreed well with predictions.

4. Full scale, 1/48th segment Humboldt Bay tests. This facility was built and operated by Pacific Gas and Electric Company at their Moss Landing Power Plant. A variety of LOCA break sizes and water pool temperatures were tested. Twenty-eight separate tests were carried out and the results were presented to the AEC in the Final Hazards Summary Report Appendices IV and V (PECO Exhibit SL-3). No tank vibrations comparable to those seen in the Condensing Facility occurred in the Humboldt Bay full scale facility, even though pool temperatures in excess of 160° F. were attained. The upwards thrust of a water-air mixture or "froth" was reported in the Humboldt Bay tests, but no significant hydrodynamic load was associated with it. No other hydrodynamic effects were reported.

5. The development of an analytical model to predict the transient pressures in the containment. This model was compared to the Transient Test Facility and the Humboldt Bay Facility results and it was shown to be conservative.

When it was decided to proceed with the Bodega Bay Nuclear Plant, an additional program was carried out which involved a new series of tests at the Moss Landing Power Plant. The original Humboldt Bay facility was restructured to simulate a full scale 1/112th segment of the Bodega Bay suppression chamber. The facility was built and operated by Pacific Gas and Electric. In the Bodega Bay tests, the vent size was changed from 14 to 24 inches and the energy being quenched per unit volume of pool water was increased. A total number of 34 tests were carried out, and the results were presented to the AEC in the Preliminary Hazards Summary Report, Appendix I (PECO Exhibit SL-4). Both one downcomer and a set of fourteen downcomers were tested. No tank vibrations comparable to those in the Condensing Tank Facility were observed with pool temperatures up to 163° F. No other significant hydrodynamic effects were reported. The measured pressure transients were compared again to analytical models and they were found to fall below the predictions.

The next series of pressure suppression tests occurred in the late 1960s when the Mark III design was being developed. The Mark III design employs horizontal instead of vertical vents. Early tests performed in a small scale facility exhibited pool swell (the lifting of a solid sheet of water by contrast to the froth observed in the Humboldt Bay tests). Condensation oscillations also occurred at the horizontal vents. Because of the small scale of these tests and the horizontal vent configuration, it was not expected that the phenomena would have any application to the Mark II containment. After a preliminary and positive review of the Mark III concept by the AEC, increased scale testing was undertaken to support that design in 1974. Three one-third scale vents and one full scale vent were tested. Condensation oscillations continued to occur. Also, impact loads were measured above the pool in this last series of tests and they were found to be significant due to the presence of a solid water ligament. These findings led to the NRC letter of April 1975 regarding LOCA hydrodynamic loads and the need to examine their potential occurrence in Mark II designs. The 4T Mark II facility was put into operation shortly thereafter. Its initial objective was to evaluate pool swell in Mark II designs and to verify the analytical model which had been developed to predict it. During the course of performing the Mark II pool swell tests, two types of condensation hydrodynamic loads were observed. During the initial phases of the LOCA, a periodic off-on mode of condensation oscillations was noted when the steam flow rates through the vents were still large. These condensation oscillations are peculiar to the Mark II design. Much later during the LOCA, a periodic off-on mode of condensation or chugging was observed at low steam flow rates. Some of the chugs produced noticeable hydrodynamic loads and substantial additional test programs were initiated from 1977 to 1980 to specify and bound their magnitude.

At about the same time as the Mark III tests were performed, the NRC was evaluating some of the vibration and noise reported during actuation of relief valves or their failure to reclose. The NRC concluded that additional margins should be provided because of a noted variation in the operating plant designs or their adherence to methods for limiting pool temperatures. This led to the NRC letter on safety relief valve loads in 1975 and to the subsequent request that quenchers be provided.

In summary, the Mark II hydrodynamic load program which was initiated after the 1975 NRC letters had no connection to the 1950's and 1960's tests or effects observed during such tests.

Q. Dr. Levy, in your above discussion, have you demonstrated the fallacy of many assertions made in the Zimmer Complaint?

A. Yes, I have.

Q. Please summarize your position as respects the Zimmer Complaint allegations.

A. My position can be summarized as follows:

- Most of the Zimmer allegations deal with the Vallecitos and the Condensing Tank Facility tests. These tests did not reproduce LOCA conditions or containment design conditions. They were carried out with the primary objective of showing that condensation of steam could be complete and they proved that this would indeed occur as long as the vents were submerged and the pool temperatures were kept below values which were prohibited by design and operation of the plant. To establish such limits, it was necessary to carry these early tests to conditions where hydrodynamic effects were present and quite severe; however, these effects were precluded from occurring in operating nuclear power plants by operating temperature restrictions which I have previously discussed.

- Many of the allegations such as upward throwing of water-air mixture in the Humboldt Bay and Bodega Bay tests have been reported in submittals to the AEC and the technical community. No significance was attached to such observations until the Mark III full scale tests were performed in 1974 and 1975.

- Implications are made in the Complaint based on the fact that several General Electric reports were kept proprietary. The reports were classified proprietary for commercial reasons, i.e., to avoid disseminating development information acquired with company funds to commercial competitors.

Summary and typical non-proprietary versions of the most relevant results were included in Safety Analysis Reports. Proprietary versions of the full reports were always available to the AEC and many were transmitted under a proprietary arrangement.

Q. Are there any additional allegations of that Complaint which you wish to address?

A. Yes, there are. There is an implication in the Zimmer complaint that the Mark II design was developed in violation of General Electric Nuclear Safety Criteria or available full scale test information. In fact, as pointed out in the paper by D.R. Miller, Exhibit SL-2, "a very conservative approach is taken in the selection of design criteria which relate to the condensation process. Specifically, these design parameters are established in strict adherence to the configurations tested at Moss Landing". No deviation from the Moss Landing tests was permitted in the three most important parameters: vent diameter, the maximum vent flow rate, and the maximum energy quenched per unit volume of suppression pool associated with each vent. The only design flexibility permitted was in overall containment volume, number of vents, vent resistance (i.e. vent length), and containment design pressure. Any such allowed flexibility was always checked against the Humboldt and Bodega Bay test results as illustrated in the Miller paper and was fully supported by analytical evaluation.

Finally, the Zimmer complaint contains many allegations of fraud based upon the proprietary nature of GE reports. Yet, the facts show that the significant results of the Humboldt Bay and Bodega Bay tests were included in their Safety Reports, as evidenced in PECO Exhibits SL-3 and SL-4. Many of the same results have been published in the open literature. Furthermore, the AEC/NRC witnessed some of the tests and had access to other test data if they so desired. Finally, they were given copies of proprietary reports when they wished to have them. GEAP-3143 is typical of reports in that category.

Q. Dr. Levy, what is your position respecting Dr. Hanauer's view that the size and complexity of the Mark II program in the mid-1970's is irrelevant to whether those loads should have been discovered prior to that time?

A. I strongly disagree with his position. The size and duration of the Mark II program shows how difficult it was to identify and characterize the hydrodynamic loads associated with the Mark II configuration. As already noted, the vibrations observed in the Condensing Test Facility had nothing to do with the condensation oscillations of importance to Mark II. Similarly, the Mark II condensation oscillations are different from those of the Mark III. Again, a froth type of water upsurge produces negligible hydrodynamic effects when compared to those produced by a solid sheet of water. Finally, intermittent condensation within vents has been observed and reported in early tests, but they did not produce noticeable loads. Dr. Hanauer has not offered any concrete evidence to show that the relevant Mark II phenomena could and should have been identified earlier. A multitude of engineers, designers, and regulators saw the information he refers to and also failed to identify the loads.

Q. Does this conclude your sur-rebuttal testimony?

A. Yes, it does.

PECO STATEMENT NO. 9A

OM 3-14-86
hbg

PENNSYLVANIA PUBLIC UTILITY COMMISSION
V. PHILADELPHIA ELECTRIC COMPANY,
DOCKET NO. R-850152

REBUTTAL TESTIMONY OF ROGER J. MATTSON

ENGINEERING RESTRAINTS TO SCHEDULE ACCELERATION DUE
TO LATE REGULATORY CHANGES
MARK II CONTAINMENT ISSUES
LICENSING CONSTRAINTS TO SCHEDULE ACCELERATION
REBUTTAL OF WILLIAM B. HALL
LGS/SSES/LASALLE COMPARISONS

FEBRUARY 19, 1986

REBUTTAL TESTIMONY OF ROGER MATTSON

Q. Please state your name and business address for the record.

A. I am Roger Mattson, and my business address is: 2600 Virginia Avenue, N.W., Washington, D.C., 20037.

Q. Are you the same Roger Mattson who has previously presented testimony in this proceeding?

A. Yes, I am. My professional experience and other qualifications are stated in my prepared direct testimony, PECo Statement No. 9.

Q. What is the purpose of your rebuttal testimony?

A. I have reviewed all or portions of the testimony of Stephen H. Hanauer and James J. O'Brien filed upon behalf of the Office of Consumer Advocate, and of Dennis P. Dougherty, Robert A. Rosenthal and William B. Hall filed upon behalf of Trial Staff in this proceeding. The purpose of my testimony is to provide for consideration by the Commission and the Administrative Law Judge the opinions which I have formed as a result of my evaluation of the positions of these witnesses.

Q. Would you please summarize the OCA opinions.

A. Mr. O'Brien has testified that, absent certain decisions made by Philadelphia Electric Company respecting the completion date of Limerick 1 and Common, that plant could have been completed in July 1982. In advancing this position, Mr. O'Brien relies upon the opinion of Dr. Hanauer that Limerick 1 could have complied with all Nuclear Regulatory Commission (NRC) requirements (including specific requirements concerning the installation of safety systems to reduce the risk of occurrence of Anticipated Transients Without Scram, the installation of equipment and systems to enhance fire protection, the qualification of mechanical and electrical equipment, and the changes in plant design to comply with NRC requirements adopted in response to the TMI accident) and could, in fact, have received a license permitting fuel load by July 1982. Based on the absence of support provided by Dr. Hanauer for this opinion, my knowledge of actual Limerick licensing events derived from my position as a senior NRC Staff manager of the Limerick licensing effort, and my knowledge of Commissioners' positions and views on these subjects during this period, I have concluded and will demonstrate that Dr. Hanauer's opinions are in error.

Dr. Hanauer has also stated a position respecting the significance and meaning to be attached in this proceeding to the discovery and investigation in the mid-1970s of certain hydrodynamic loads not previously recognized in the design of the BWR Mark II containment. In this testimony, I present my conclusion and supportive reasons as to why Dr. Hanauer's position is in error.

I have also reviewed the position of Trial Staff witnesses Dougherty and Rosenthal that Limerick 1 and Common Plant could have been completed in April 1981. For reasons similar to my conclusions respecting errors in the OCA testimony, I conclude that the opinions of these witnesses are in error.

Finally, my review of the testimony of Trial Staff witness Hall indicates that this witness has misunderstood or taken out of context certain statements from NRC and other documents. I will correct these and other mistakes by this witness.

1. <u>REBUTTAL OF OCA WITNESS HANAUER REGARDING MARK II CONTAINMENT</u>

Q. Please begin by explaining the errors made by OCA witness Hanauer in discussing the mid-1970s discovery of hydrodynamic loads affecting the Mark II containment. What was the first plant to receive Atomic Energy Commission (AEC) approval to construct a pressure-suppression containment?

A. The first plant to receive AEC approval of a pressure-suppression containment was the Humboldt Bay plant which was constructed by Pacific Gas and Electric Company (PG&E).

Q. What was the basis for the AEC accepting the Humboldt Bay design?

A. The AEC accepted the Humboldt Bay containment on two bases. The first was a series of tests that was performed by General Electric (GE) and PG&E which demonstrated that a pressure-suppression containment was feasible. The second was the design analysis which showed that the containment could withstand the maximum pressure resulting from a loss-of-coolant accident (LOCA).

Q. Please describe the various tests which were performed by GE and PG&E early in the development of the pressure suppression concept.

A. Initially, in the late 1950's, GE performed tests at the Valicetos power plant to determine if the concept of a pressure suppression containment was feasible. Later, PG&E determined that pressure suppression could have advantages for the containment at its Humboldt Bay plant and decided to perform and support additional tests at the PG&E Moss Landing power plant and at the GE facility in San Jose. From these tests came information about suppression pool size and downcomer geometry and data needed to develop models of containment performance.

Q. Were these initial test results accepted by the AEC as the basis for approving the Humboldt Bay design?

A. No. After the AEC and the Advisory Committee on Reactor Safeguards (ACRS) reviewed the early test results, both recommended that PG&E perform additional tests in a full scale configuration that better matched the Humboldt Bay design.

The ACRS views were expressed in a letter dated March 19, 1960, and in discussions between John A. McCone, Chairman of the AEC and Dr. Leslie Silverman, Chairman of the ACRS. The results of these exchanges were conveyed to Mr. Sutherland, President of PG&E via a telephone conversation, documented in a March 31, 1960 memorandum from Mr. McCone to the AEC General Manager. In this memorandum, Mr. McCone stated:

> "After talking with Dr. Silverman, I talked with Mr. Sutherland, President of PG&E and advised him that it was the personal opinion of Dr. Silverman, several members of the AEC (names not mentioned) and of me, personally, that if the tests were conducted with 1200 pound pressure steam (the pressure expected under the maximum probable incident) and with the 14 inch pipe downcomer and testing 1/48th of the suppression system, satisfactory results from such tests would remove concern over the adequacy of the proposed containment system.
>
> Dr. Silverman injected the question of vibration and proper placing of pipes which I assume will be taken care of by structural design."

As a result, PG&E and GE built a new test facility at Moss Landing which represented 1/48 of the full Humboldt Bay reactor, drywell, and suppression chamber. Using this new test facility, PG&E and GE ran additional tests to verify the Humboldt Bay design. The ACRS visited the facility during the tests and AEC Staff members were also present.

Q. Were these tests accepted by the AEC?

A. Yes, the tests were accepted as sufficient for the licensing of Humboldt Bay by both the AEC Staff in its June 21, 1960 report evaluating the Humboldt Bay containment and the ACRS in its June 27, 1960 letter.

Q. You have told us how the AEC Staff and ACRS were involved in the design of the test program for the Humboldt Bay plant. Was this the limit of their involvement?

A. No. Following its review of the Humboldt Bay "Preliminary Hazard Summary Report," which described the tests and the results, the ACRS recommended that the Humboldt Bay suppression pool incorporate baffles. This was stated in its June 27, 1960 letter after being raised in the June 21, 1960 AEC Staff report to the ACRS. The ACRS and AEC Staff believed the baffles would conform the Humboldt Bay design more closely to the test facility configuration. The AEC Staff continued to ask other utilities using the pressure-suppression containment to discuss their plans to incorporate baffles or justify the omission of baffles.

Another example of AEC involvement in the design of the pressure suppression chamber is the addition of a common header for the downcomers. This vent header was installed largely because of ACRS and AEC staff concerns with the possibility of asymmetric discharges uncovering one or more of the downcomers. The addition of baffles in the drywell to avoid direct impingement on vent openings was also a response to these concerns. These two design changes are described in the June 21, 1960 AEC Staff report to the ACRS.

These examples of design changes and additional testing show there was direct involvement by both the AEC Staff and the ACRS in the development program and initial design of the pressure-suppression containment.

Q. Were additional tests then required to support the Bodega Bay Mark I containment?

A. Yes. In 1961, PG&E filed an application with the AEC to construct the Bodega Bay nuclear power plant. Because the containment design of Bodega Bay would be different from Humboldt Bay, it was decided to perform additional tests to assure the acceptability of the new containment. Examples of differences between the Bodega Bay and Humboldt Bay design are (1) larger diameter downcomers for

Bodega (24 inch vs. 14 inch), (2) a larger suppression pool for Bodega, (3) a greater energy absorption rate for the Bodega suppression pool, and (4) the use of the torus-type suppression pool for Bodega Bay.

Tests of the Bodega Bay design were performed after modifying the facility at Moss Landing to represent 1/112 of the Bodega Bay suppression pool. The tests were run and the results were found acceptable by the AEC as a basis for designing the Bodega Bay containment. This is another example of AEC involvement in the development of the pressure-suppression containment concept.

Q. Have you any further comment on either the Humboldt Bay or Bodega Bay tests?

A. The principal objective of the tests of the Humboldt Bay and Bodega Bay designs was to confirm their ability to absorb the energy necessary to ensure condensation of the steam discharged during a loss-of-coolant-accident, and to maintain the integrity of the primary containment under the peak pressure loads following a LOCA. Some dynamic phenomena were observed in these early tests, but these were considered to be insignificant or due to specific characteristics of the test facility. AEC and ACRS accepted that these phenomena were insignificant or would not be experienced in plant operation. Subsequent Mark I and Mark II containments were referenced to the Humboldt Bay and Bodega Bay tests for design and licensing purposes. When applicants were asked to justify the applicability of the earlier tests to their containment design, both the questions and the answers were in terms of design parameters that related to pool temperature and drywell and wetwell pressure.

Q. Were dynamic loads ever taken into account in other aspects of the early licensing process?

A. They were. For example, the hydrodynamic forces occurring in the primary coolant system, such as water hammer, were of safety and engineering interest, as were jet loads in the drywell following a primary system break. Reaction and impingement forces were taken into account in the design of relief valve discharges into the suppression pool. However, the significance of hydrodynamic forces in the suppression pool was not recognized by either the industry or the AEC prior to the mid 1970s.

Q. Are you familiar with Dr. Hanauer's September 20, 1972 memorandum identifying concerns with pressure-suppression containments?

A. Yes.

Q. In this 1972 memorandum, did Dr. Hanauer describe any concerns with hydrodynamic loads on the pressure suppression system?

A. No, he did not.

Q. What are the technical issues contained in Dr. Hanauer's memorandum?

A. In his 1972 memorandum, Dr. Hanauer lists a number of technical concerns, including the following:

(1) The judgment that design applications of data from earlier experiments used to determine the rate of steam condensation may not be conservative even though the data on the rate of condensation were conservative;

(2) The hydrogen generation associated with a LOCA is a more serious problem in the smaller pressure suppression containment;

(3) There is no leakage test to assure that the dividers between the two volumes which make up a pressure-suppression containment will prohibit steam from bypassing the condensation process;

(4) The vacuum relief valves used in the GE containments, except Mark III, may stick open and result in a path for steam bypass of the condensation process;

(5) The smaller size of the pressure-suppression containment makes it overcrowded which in turn limits access to components for maintenance; and

(6) Although the subcompartments in a pressure-suppression containment were designed to withstand the pressure from a pipe break, the capability had not yet been tested.

These concerns relate primarily to steam bypass of the condensation capability of the pressure-suppression system and do not indicate any concerns with hydrodynamic loads.

Q. Thus far, your discussion has centered on the containment design consideration following a LOCA. What type of design considerations were associated with the discharge of safety relief valves (SRVs)?

A. Originally, the discharges of SRVs were not specifically considered in the design of pressure-suppression containments, apparently because it was believed that if the design was sufficient to withstand a LOCA, it could easily accommodate SRV discharges. Indeed, at least as late as an October 25, 1973 meeting of the ACRS Grand Gulf subcommittee, the AEC Assistant Project Manager for the Grand Gulf plant could say to members of the ACRS, the AEC staff, Bechtel and General Electric, without generating controversy, "...whatever effects there are in bubble formation from relief valve lifting has got to be a lot less than what is going to happen during the blowdown, a LOCA blowdown."

Q. Was there any early Mark I operating experience with SRV discharges?

A. Yes, data on SRV discharges began to accumulate soon after the Mark I plants started to operate. In 1971, the Monticello plant discovered torus baffle damage that was associated with relief valve discharge. After the AEC requested inspections of baffles and other torus structures, Oyster Creek, Nine Mile Point-1 and Humboldt Bay also discovered baffle damage. At Quad Cities, an investigation into the cause of broken hangers on the suction header concluded that inadequate installation plus the additional loads from relief valve vent clearing caused the damage.

In addition to these U.S. experiences, the Wuergassen plant in Germany experienced an extended steam discharge from a stuck relief valve which elevated the pool temperature and produced pressure oscillations.

Q. How did the AEC, the licensee, and GE respond to these incidents involving SRV discharges?

A. The experience at Wuergassen was considered to be not applicable to U.S. plants since they are not operated in the pool temperature range at which the pressure oscillations occurred.

With respect to the baffle damage that occurred in U.S. plants, an analysis was done to determine the force at the downcomer discharge and then at various distances away from the discharge. The licensees decided that removal of the baffles would eliminate the problem and proposed this to the AEC. Justification for removing the baffles was supported by reference to the Bodega Bay, multiple-event tests performed in 1963. The AEC accepted baffle removal as a satisfactory corrective measure.

GE performed a series of tests at Quad Cities to measure the forces associated with the SRV vent clearing phenomena. Following the tests, GE prepared NEDO-10859 which described SRV opening, vent clearing, pressure oscillations in the wetwell, and structural response of the torus. After reviewing the report and other information submitted by GE, the AEC concluded that the data were not adequate to confirm the GE model of vent clearing.

Q. Did the SRV and LOCA loads subsequently become a serious licensing concern?

A. Yes. These loads became a concern during 1974 and caused the NRC to issue a series of letters in early 1975 to BWR licensees and applicants regarding these phenomena.

Q. What specifically initiated the NRC concerns expressed in the letters sent out in early 1975?

A. There were two phenomena addressed in the NRC letters to BWR Mark I and Mark II owners in early 1975.

The letters sent to Mark I owners on or about February 15, 1975 and to Mark II owners on or about April 23, 1975 addressed the steam vent clearing phenomena and steam quenching phenomena associated with safety and relief valve discharge into the suppression pool. An April 17, 1975 letter sent to both Mark I and Mark II owners addressed the suppression pool hydrodynamic loads during a loss-of-coolant accident. Different events led to the AEC concerns with respect to safety relief valve discharge phenomena and LOCA pool load phenomena.

Q. Will you describe the events leading to the NRC concerns with the safety relief valve discharge?

A. At the beginning of 1973, the AEC staff, the BWR plant owners, and the associated technical community felt that the dynamic loads arising from safety/relief valve discharges had been adequately resolved for operating plants by removing the baffles, adding rams heads or other fittings to the discharge pipes, maintaining the pool temperature within operating limits, and making structural improvements in the ring header supports and pipelines. Remaining as an open issue, however, was the AEC view that the vent clearing model had not yet been confirmed by adequate test data.

During November 1973, the startup tests at Brown's Ferry produced significant vibration and noise. These effects were associated with the air clearing transient and were described in the "Second Interim Report on Vibrations in Torus and Torus-Ring Header" submitted by TVA in May 7, 1979. They were reduced to levels that were deemed acceptable in subsequent testing, through modifications to the ring header supports and the relief valve tailpipes.

In May of 1974, a relief valve at Brown's Ferry failed to close and blew steam into the suppression pool for nine minutes. While a later inspection disclosed that 15 of 16 torus spray header hangers were disconnected, no causal relationship with the SRV blowdown was established. A similar extended discharge at Peach Bottom caused the AEC to issue Reactor Operations Bulletin 74-14 (November, 1974). In this Bulletin, the AEC stated that occurrences at Brown's Ferry 1 and Peach Bottom indicated that a situation may have been approached in which steam quenching was or could have been erratic. The actions requested were related to procedural approaches for ensuring that the pool temperatures remained within acceptable levels.

Following the NRC Staff evaluation of the responses to the Bulletin, which varied widely both in their details and in the degree of adherence to the interim operating procedures recommended by GE, the NRC issued a letter in February 1975 to owners of operating BWR Mark I reactors requesting that programs be established to evaluate the potential effects of SRV vent clearing phenomena and of steam quenching vibration. In late April, a similar letter about SRV discharge was sent to the remaining BWR owners.

Q. Will you now describe the events associated with the Mark III tests that led to the letter from NRC to the BWR owners on April 17, 1975?

A. These events began with the ACRS subcommittee meeting in October 1973, on the Grand Gulf plant. Grand Gulf was the first Mark III containment to be brought before the AEC and the ACRS for licensing. Because the vents between the drywell and the suppression pool were horizontal and therefore different from any previous designs, a series of tests was planned to confirm the vent clearing model and then to characterize any suppression pool hydrodynamic loads.

By mid-1974, data from the tests had shown that pool swell loads would require relocating some of the Grand Gulf pool structures. More definitive 1/3 scale tests were initiated in the summer of 1974 and continued into 1975. Although the basis for applying these test data to specific Mark I and Mark II containment designs had not yet been established, the NRC considered that an evaluation by BWR owners of the potential magnitude and effect of hydrodynamic loads associated with a LOCA should be performed. This evaluation was requested by the NRC letter issued April 17, 1975.

The later Mark III test results, together with operating experience in the U.S. and elsewhere, also caused concern with the hydrodynamic loads resulting from relief valve discharges.

Q. What was the immediate consequence of the NRC letters to BWR owners concerning the LOCA and relief valve hydrodynamic phenomena?

A. It became evident that the effort and time necessary to adequately characterize the phenomena and to assess the loads for specific designs would be significant. The Mark II owners formed an owners' group as did the Mark I owners. They established plans for tests and analyses that would provide a basis for design changes, if necessary. A Lead Plant Program (LPP) was aimed at short-term conservative conclusions which could be applied to plants designated as lead plants. A Long Term Program (LTP) was intended to provide the basic understanding necessary for more realistic and less costly design loads for plants that were less advanced in construction and had longer lead times.

Q. What were the specific objectives of the Mark II Lead Plant and Long Term Programs?

A. The designation of the lead plants to be supported by the LPP was based on the stage of containment construction. The objective of the Lead Plant Program was to establish conservative design basis loads appropriate for the anticipated life of the Mark II facilities in the program. Bounding load specifications for certain loads were used for the lead plants (Zimmer, Shoreham and LaSalle). It was intended that this additional conservatism would avoid unnecessary delay in completion of the lead plants.

The objectives of the Long Term Program were to: (1) provide justification through test and analysis for a reduction in some of the bounding loads selected in the Lead Plant Program; and (2) provide additional confirmation of other loads used for the lead plants, thus providing a basis for more realistic loads to be used for the remaining Mark II plants.

Q. Did the results of the Mark II Long Term Program have any impact on the lead plant loads?

A. Yes, they did. Some of the bounding loads used by the NRC Staff for the lead plants were shown by LTP test data to not be conservative. This prompted a review of the lead plant loads. For example, in early 1980, foreign test data indicated that the so-called 4T measurements (Temporary Tall Tank Tests) did not represent an upper bound on chugging loads. At about the same time, 4T tests on condensation oscillation indicated that the NUREG-0487 (the NRC report that set the load criteria for the LPP) loads did not bound all frequencies and amplitudes. It was then concluded that modifications should be made to the generic lead plant condensation oscillation and chugging loads that had been specified by the NRC in NUREG-0487.

This introduced costs for the LPP plants that were prudently avoided by PECo's decision to be a long term plant.

Q. What conclusions can you draw from the delays and reassessments required during the extended Lead Plant Program?

A. One conclusion that seems inescapable is that the problem of characterizing the new hydrodynamic loads was extremely complex. While it is true, as Dr. Hanauer states, that no new laws of nature were discovered that showed the need for new design loads, it is abundantly clear that the ways in which the laws of nature would be manifest in the hydrodynamic behavior of pressure suppression containment was unsuspected and unknown until they were illuminated by operating experience and advancing knowledge. The Mark II program can be seen as a classic example of an improved understanding first clarifying the questions before supplying the answers. It confirms for me that these phenomena and their potential effects were not known in the 1950s and 1960s so as to justify Dr. Hanauer's view that neglecting to include them in the design basis was a technical error.

A second conclusion is that the Mark II plants that were not impelled by circumstance to move quickly ahead in adopting design modifications acted prudently by waiting and thereby decreased their efforts and costs.

Q. Can you provide a general description of the Mark II licensing program?

A. Yes, during the performance of the Mark II program, the NRC, the owners, the architect-engineers, the experimenters and the analysts were all faced with the same questions:.

- Have all phenomena relevant to the design basis been identified?
- Have these phenomena been characterized (modeled) adequately to allow calculation of design loads?
- Does enough data exist to confirm the models across the full range of their application?
- Will the resulting design have an adequate margin of safety?

It was necessary for all of the parties to answer these questions affirmatively before a plant could be built and licensed. They would also have to keep in mind that these questions had previously been answered affirmatively, before new information in the early 1970s required a re-examination. It was to be expected that great caution would be exercised in arriving at the respective new positions.

The program was, in my view, notable for the frequency and content of the communication among the parties mentioned above. The ACRS and the NRC Staff were briefed regularly and thoroughly on the conduct of the BWR Owners' Group program and the data being collected. The NRC, of course, made publicly available the results of its own research on hydrodynamic phenomena in pressure suppression containment. Based on my experience as a senior manager of the NRC review at various times from 1977 until 1982, I believe the NRC Staff and ACRS influenced the extent and content of the Mark II program. It is quite obvious that the applicants and their supporting contractors were unlikely to consider that the questions listed above were adequately answered unless they perceived that the NRC also was or would be satisfied. Applicants, like Limerick, were faced with the need to balance the direct and indirect (delay) costs of further tests and analysis and the potential costs of excessive or inadequate design conservatism. It seems to me that, under the circumstances, PECo made prudent and timely use of results from the Mark II Long Term Program in determining its plant unique requirements.

Q. Did the NRC establish new requirements during the course of the Mark II program (i.e., 1975-1982)?

A. Clearly, it did. The NRC licensing requirements are generically stated in its published regulations. But the requirements are more clearly and specifically seen in the Safety Evaluation Report which states the technical basis for issuing a license to a specific plant. In the case of Mark II plants, the licensing requirements were, until early 1975, comparable to those used for Mark I pressure suppression containments. Following that time, there were new requirements that several new loads be included in the design basis and that new load combinations be taken into account. The nature and evolution of these new requirements are more fully described by PECo witness Salomon Levy. I am in general agreement with his description, and I too have elaborated on these matters, below.

Q. Dr. Hanauer has given several reasons why the resolution of the Mark II hydrodynamic load issues took so long. Do you wish to comment on these?

A. Yes, I do. First, let me point out that although Dr. Hanauer listed several items which he referred to as planned steps in the Mark II program, he did not explain how this list of activities affected the duration of the program, nor why it proved to be longer and more expensive than it was expected to be.

In my view, part of the explanation lies in the facts I have already raised.

That is, there was but limited understanding, even in 1975, of the nature and potential effects of the phenomena to be studied. The full range of the tests that would be needed to characterize the phenomena - and to meet the evolving NRC requirements for analysis - was simply not clear in 1975. The chronology of events from 1975 to 1978, which the NRC staff included in NUREG-0487, Appendix A, shows the iterative, interactive nature of this program. For example, there were 22 NRC meetings with Mark II owners. It was the technical complexity of the issues to be resolved, and not the planned steps toward their resolution, that was responsible for the duration of the Mark II program.

Q. Do you have comments on the chronology of the Mark II program that was submitted by Dr. Hanauer as SHH-4?

A. Yes, I believe that certain points in the chronology should be clarified.

First, the period during which the Mark III tests produced information relevant to the Mark II design is not 1972-75 as shown. The first relevant data were produced in the spring of 1974, largely as a result of the need to respond to ACRS interests. The Mark III test data resulted first in some changes to the pool structure of the Grand Gulf plant. There was then an interval during which the relevance of these results to Mark I and Mark II plants was assessed.

Second, the period from September to December 1974 was marked by correspondence and meetings between GE and the AEC on the relevance of Mark III design analyses to Mark I and Mark II containments. Because each design was developed independently by the Mark II owners and their architect-engineers, NRC staff concluded that a generic resolution would not be possible so that letters to each plant requesting an evaluation would be required, and these were sent in early 1975.

Q. Did the Nuclear Regulatory Commission make changes in the licensing requirements that were related to the new loads applied to Limerick after a construction permit was issued for the plant?

A. Yes, and these changes led to expenses for the construction of Limerick that were in excess of those that were strictly necessary to accommodate the additional hydrodynamic loads.

Q. What were these changes made by the NRC?

A. The changes made by NRC that bore a direct relationship to the new loads for the Mark II were the following:

1. Addition of SRV air clearing loads within the design basis for the plant;
2. Addition of loads associated with the accidental opening of one SRV during the course of a design basis loss-of-coolant-accident, in combination with the design basis seismic loads; and
3. Consideration of multiple, simultaneous SRV openings.

NRC changes that indirectly affected costs associated with the new loads in the Mark II design were the following:

1. More detailed assessment of the nature and effects of dynamic load propagation in the containment and other portions of the plant in the structural design reanalysis occasioned by the definition of new hydrodynamic loads and by new NRC Staff requirements on seismic modeling and soil-structure interaction (e.g. Regulatory Guide 1.60);
2. More detailed analysis of the reactor and the containment response to a range of small, intermediate, and large break loss-of-coolant-accidents, exceeding that required for the construction permit (the

Appendix K analysis for Limerick was first approved by NRC in August 1983 in the SER for the operating license);

3. Greater reliance upon experimental verification of analytical models of the thermal and hydraulic response of the plant to accidents;

4. A more mechanistic treatment of the details of accident sequences, including imposition of the single failure criterion, than previously was associated with design basis accident specifications;

5. Less willingness on the part of the NRC Staff to rely on the margins to failure provided by conservative design practices and conservative postulations of design basis accidents;

6. More stringent demonstration of the quality of construction of safety-related structures systems and components;

7. Greater reliance upon tests to demonstrate the dynamic and environmental qualifications of safety-related equipment; and

8. The ever increasing use of conservatism by specialists in the NRC technical staff in the course of their reviews of license applications.

Q. Were these changes in NRC requirements foreseen by the NRC Staff in the early 1970s?

A. No, these changes occurred slowly, over a period of years. The major sources of change, in my judgment as one who was there most of the time from 1967 to 1984, were the increased occurrence of intervention in the licensing process, the nature of the public hearings wherein greater precision was required of witnesses on the hearing stand than engineers could reasonably provide, public reaction to the accident at Three Mile Island, poor construction and operations performance by a few utilities, and significant, yet gradual change in the NRC's perception and communication of how safe was safe enough. These matters were treated in some detail in my direct testimony.

Q. Could Philadelphia Electric Company have foreseen these changes in NRC requirements that either directly or indirectly affected the costs of dealing with the new Mark II loads?

A. No, if the NRC Staff was unable to see these changes in advance, then it is not reasonable to expect that PECo could have foreseen them either.

Q. After considering the history of the hydrodynamic loads discovered to be a problem in 1974 and 1975 for Mark II containments, do you have any comments on Dr. Hanauer's conclusion that General Electric committed an avoidable technical error by failing to specify these loads at some earlier time and therefore that utility expenditures made for Mark II redesign and modification were imprudent?

A. In considering this question for Pennsylvania Power and Light (PP&L) in the rate proceedings for Susquehanna 1, the Pennsylvania Public Utility Commission made its opinion clear on this prudency question in an opinion and order rendered on August 19, 1983. The OCA had asked for a disallowance of $38.6 million in PP&L's rate request for its expenditures on Mark II design changes and modifications. The Administrative Law Judge ruled in PP&L's favor by concluding that:

> "There is no support for the $38.6 million adjustment because (1) it is undisputed that PP&L expenditures to solve the containment problem were necessary to build a safe and licensable plant; (2) PP&L's efforts to evaluate and incorporate the new loads in the design of Susquehanna were prudent and essential to commercial operation of the plant; (3) the record does not demonstrate that the containment problem was reasonably discoverable at an earlier point in time; (4) the problem was not in identifying the loads, but determining the impact of the loads on the plant and how to design for the impact; and (5) there is no showing that General Electric was imprudent in the design of the containment."

I have reviewed a number of NRC and AEC documents describing the discovery, nature, and process of resolution of the hydrodynamic loads, and I have experience in the NRC staff during most of the period of interest. This background persuades me that the PPUC conclusion is clearly correct and no penalty should be assessed against PECo in this proceeding due to this matter.

2. REBUTTAL OF TESTIMONY OF WILLIAM B. HALL

Q. What is the purpose of this portion of your testimony?

A. This portion of my testimony rebuts the direct testimony of William B. Hall of the PPUC Staff.

Q. Please address that portion of Mr. Hall's testimony about which you have comments?

A. On pages 2 and 3 of Mr. Hall's testimony, the argument is made that the NRC "issued new and more stringent safety standards only when there was some showing of industry failure to meet the original safety requirements." Mr. Hall goes on to state that the shift in responsibilities for assuring safety moved from the utilities to NRC because "some utilities failed to meet minimum requirements." While it is true that some utilities did fail to meet NRC's requirements, and as a result, prompted more stringent NRC regulations, this argument does not apply to PECo. Instead, PECo demonstrated its ability to successfully construct and operate nuclear power plants. Also, PECo instituted such a successful quality assurance program that the NRC found that it did not have to conduct extensive reinspections or reconfirmation of PECo-supplied activities or data. The NRC Staff has consistently given high marks to PECO in its Systematic Assessment of Licensee Performance (SALP) reports.

Q. Were there other reasons that explain why NRC was issuing new and more stringent safety requirements other than the lack of compliance by selected licensees?

A. Yes, there are several other factors that had significant influence:

1. The lessons learned from the accident at Three Mile Island Unit 2 (TMI-2) stressed the negative impact of the traditional concentration on design basis events and brought attention to the need to design new regulations that addressed higher probability events. Operator training, operating experience, emergency planning, control room design, improved instrumentation, and technical support were areas in which NRC had not placed sufficient emphasis before the accident at TMI-2.

2. Even before the TMI-2 accident, NRC regulations had started to become more prescriptive. The state of knowledge regarding reactor safety was undergoing rapid changes in an industry that was still relatively young. Analytical tools, which were developed as a result of large-scale computerization, raised technical concerns that had never been considered before because they were beyond the state of the art.

3. The fire at the Brown's Ferry plant in 1975, which disabled much of the plant's safety equipment, and other plant operating experiences also provided new technical information about safety systems that prompted new and more stringent NRC regulations.

In sum, new and more stringent regulations were in part due to changing technology, new knowledge gained from operating experience (including the accidents at Brown's Ferry and TMI-2), and the availability of more advanced analytical techniques. The NRC's response to these dynamic events was to treat these uncertainties very conservatively.

Q. Did the technical problems discovered in the earlier nuclear plants cause the NRC to acquire a larger staff to conduct more plant reviews as Mr. Hall contends?

A. Not exactly. It is my opinion that while the technical problems, which arose from operating experience, may have contributed to the NRC's increases in staff, they were not the catalyst or major contributor. One has to examine the timing of these events to gain perspective on why this is true. The NRC significantly increased its staffing levels between about 1970 and 1974, largely in response to increased public attention and a much larger degree of intervention in licensing hearings. Up until this time, the operating experiences with nuclear power plants had been generally positive; few generic safety problems had been discovered. The increased public scrutiny arose in several ways, including the following: (1) the Calvert Cliffs decision in the early 1970s that resulted in the requirement for licensees to submit environmental reports, (2) the controversies that grew out of the Emergency Core Cooling System (ECCS) proceedings in the early 1970s, (3) emergence in the early 1970s of the As Low As Reasonably Achievable (ALARA) requirements for reactor effluents that eventually led to Appendix I to 10 CFR 50, and (4) increased attention and controversy over seismic requirements. The effects of large increases in NRC staffing between 1940 and 1974 were not fully realized until the NRC issued its Standard Review Plan in 1975, at which time many new detailed criteria were suddenly being considered for backfit. It was only after 1975, especially after the Brown's Ferry fire, that operating experience began to reveal a growing number of safety concerns that prompted further increases in NRC staffing and adjustment of priorities.

Q. In your opinion, did PECo effectively manage the NRC imposed changes and respond prudently to avoid additional unnecessary costs?

A. Yes, and to show why, I refer to page 125 of one of the reports cited by Mr. Hall, "Nuclear Power in an Age of Uncertainty." Therein the Office of Technology Assessment (OTA) provides some examples of factors that contribute to a well-run utility. These include (1) upper management commitment to attaining and maintaining high standards of safety and consistent quality assurance, (2) concentration of authority in upper management to assure that complex operations are centrally monitored and controlled, (3) proper management and control to assure that the wide diversity of activities is well controlled and that scheduling problems are avoided, (4) ensuring sufficient management and staff resources and maintaining adequate training and retraining programs, and (5) obtaining managers and engineers with sufficient experience in constructing nuclear power plants. As evidenced by the actions described by PECo witness Kemper, PECo incorporated these concepts in the construction of Limerick 1. Also, PECo management took full responsibility for Limerick's licensing as evidenced by the following actions that were undertaken:

1. An organization was established to monitor and control licensing;
2. PECo developed an automated, computerized status summary tracking program for licensing activities;
3. Information received by PECo from the Peach Bottom plant was, if appropriate, applied to Limerick;
4. PECo used interdisciplinary teams of in-house and contractor experts to prepare thorough responses to NRC questions; and
5. Letters were used to respond to staff questions, thus eliminating the delay of NRC waiting for formal amendments of Safety Analysis Reports.

These management actions illustrate PECo's prompt and responsible reaction to the changes in the regulatory process.

Q. Did the NRC ever officially document its views on PECo's management performance?

A. Yes, this took place in the NRC's Systematic Assessment of Licensee Performance (SALP) reviews.

Q. How frequently was PECo evaluated in SALP reviews and what were the NRC's conclusions?

A. The NRC performed four SALP reviews of PECo between July 1980 and October 1984, and PECo was generally rated quite well. High marks were given to PECo's commitment to quality assurance and effective and responsive management. For example, in its January 16, 1984 SALP report, the NRC provided the following overview statement of the Limerick nuclear station.

> "The licensee has continued to manage the construction program for Units 1 and 2 well. By providing knowledgeable staffs, and by effectively controlling the Constructor and Architect-Engineer, the licensee has achieved a requisite level of quality. Additionally, the technical knowledge and expertise of the licensee's construction Quality Assurance organization has contributed substantially to the overall effort."

The NRC reached similar conclusions about PECo's licensing activities in one of its SALP reviews that supports the description of sound management given in the OTA report cited by Mr. Hall. The April 26, 1985 SALP report says, in part:

> "The licensee's management consistently exercised firm control over the licensing activities performed by its contractors and maintained effective communications between its contractors, its own staff, the NRR-staff and the NRR staff's contractors.
>
> "The success of the licensee's effort to assure quality is evident in that the many submittals made during this period have been virtually always submitted in a timely manner, have been complete and thorough (requiring very few revisions for correction of errors) and are reflective of a

power plant design that is well controlled and verified by licensee personnel prior to submittal to NRC.

"The licensee's management and staff have consistently demonstrated a thorough understanding of technical issues. Participation in a variety of industry working groups contributes to this understanding as does the extensive experience of much of the licensee's staff in operating the Peach Bottom Atomic Power Station for more than a decade. The licensee's strengths in this area were particularly evident in the resolution of power systems, electrical and instrumentation systems, and containment systems issues during the rating period.

"On occasions, when the licensee deviated from staff guidance, the licensee has consistently provided good technical justification for such deviations. Examples included several fire protection program issues, seismic/dynamic equipment qualification, lifting of leads for surveillance testing and separation criteria for electrical cable trays, panel meters and terminal blocks. The licensee's response to these and other similar issues was virtually always set forth in a technically sound and thorough manner.

"A noteworthy aspect of the licensee's performance in this area has been the lack of hesitation to develop and submit additional information and to support meetings whenever required to resolve issues. The licensee has also cooperated with the staff in response to several inquiries related to generic issues (e.g., USI-A-45, Decay Heat Removal)."

Q. As Mr. Hall notes, delays in plant completion have been attributed to a number of causes other than regulatory-induced delays, such as lower load growth, financial problems, poor utility management practices, and other utility-induced delays. Can you comment on the relative contributions to delays that were caused by the regulators versus those that were self-initiated by the utilities?

A. The EPRI report cited by Mr. Hall, "An Analysis of Power Plant Construction Lead Times," provides such an analysis. By aggregating the results of a series of case studies, the EPRI report found two broad types of delay, which were categorized according to their sources. These were:

> "Out-of-scope work (involuntary delays caused by the actions of an agency other than the constructing utility) and deliberate delays (caused by the voluntary actions of the constructing utility)....Out-of-scope delays occur when the scope of the project is changed, usually as the result of regulatory actions, but occasionally because of more conventional reasons such as late deliveries of materials or strikes. Out-of-scope work stretches the schedule; however active construction usually continues. Deliberate delays can be caused by problems both within the utility's control, such as the need to reallocate labor due to changes in priorities; however, deliberate delays are most often caused by external events, such as load growth shortfalls and financial difficulties. Deliberate delays are also called construction slowdowns because they stretch the schedule through deliberate slowing or stopping of construction activity. Thus, out-of-scope work and deliberate delays can be distinguished in two ways: by the cause of the delay or by the level of construction activity observed."

Using these definitions, the report found that:

> "The average nuclear unit from the case studies has experienced 43 months of construction related delay -- of which 78 percent were related to out-of-scope work and 22 percent were deliberate delays."

In sum, the EPRI report found that most of the delays were caused by non-utiltity related reasons and were in fact caused by regulatory changes and related redesign work.

Q. In the case of Limerick, did its schedule expose the project to additional NRC requirements as Mr. Hall suggests as a possibility?

A. No, at least not significantly. As I will discuss below and as other PECO witnesses describe, because of Limerick's high surrounding population density and highly contested hearings, the NRC, in my opinion, would have imposed upon Limerick virtually all of the regulatory requirements which it did impose regardless of the timing of Limerick's construction completion.

3. <u>REBUTTAL OF OCA PLANT COMPARISONS</u>

Q. Dr. Mattson, the OCA witnesses make comparisons among the fuel load dates of

Limerick, Susquehanna and LaSalle. Have you any comment about the propriety of these comparisons?

A. As a rule, caution must be exercised in comparing the licensing experiences of plants. Direct comparisons can be illusory because they may not account for a number of factors that can reasonably explain why licensing dates differ. Examples of such factors include:

1. Design Differences - Plants that are of the same reactor type can differ significantly. Even standardized reactors, once built, can differ greatly, especially in the balance of plant.

2. Site Differences - Every site has its own peculiarities that may make licensing more or less difficult. In Limerick's case, high population density led to more stringent application of NRC licensing criteria.

3. Regulatory Performance - Applicants that provide timely and complete information and establish good communications with the NRC's licensing staff can affect the length of licensing review.

4. Licensing Environment - If a licensing case is highly contested, it is likely that the NRC will be less flexible in permitting deviations from requirements. The NRC's inflexibility may not be related to the quality of the plant or its performance, but rather to a desire to avoid troublesome litigation.

Q. Dr. Mattson, can you identify any specific items respecting licensing which were ignored by the OCA witnesses in their comparison?

A. Yes, I can. For example, the number of outstanding and confirmatory issues that were identified by the NRC in its Safety Evaluation Report (SER) and supplemental SERs (SSERs) provides some idea of the number of safety issues that were raised in the Operating License (OL) review. A direct comparison of the numbers of these issues among plants does not provide very useful information because each plant has different reviewers who often place different emphasis on particular issues. It is more useful to discuss the percent of those outstanding and confirmatory issues that NRC management allows to be resolved after the OL is granted, as license conditions, because it gives an indication of the flexibility of the licensing review. As I show in Schedule 1, Limerick had 97 outstanding and confirmatory items that accumulated through the SER and the three SSER's. However, only 5 of these issues were not required to be resolved before granting of an OL; the ratio of issues not allowed to be delayed to the number of outstanding and confirmatory items is about five percent. The Susquehanna plant had more outstanding and confirmatory items (109), and PP&L was allowed to carry 22 of these into the OL as operating conditions. This ratio was approximately 20 percent. The LaSalle plant had the fewest number of outstanding and confirmatory issues (29) but was allowed to take 12 of these as operating conditions. This ratio was approximately 41 percent.

Q. Please explain the significance of this data?

A. The Limerick plant was highly contested during ASLB hearings and had a far greater number of days in hearings than either LaSalle or Susquehanna. Because the plant was so highly contested, the NRC was more inclined to require that the controversial technical issues be resolved before an OL was granted. For example, the fire protection and environmental qualification programs were required to be essentially complete at Limerick, but not at the other plants, before the OL was granted.

Q. Does the number of conditions that each plant was allowed to carry into its license confirm the above observation?

A. Yes, as shown in Schedule 2. In the case of the three plants compared by the OCA, Limerick had far fewer total licensing conditions (34 in all) compared to 66 for La Salle and 49 for Susquehanna. Also, the number of formal exemptions from NRC regulations in 10 CFR is another indicator of how strict the NRC was in requiring adherence to its licensing requirements. According to the OL, SER, and SSERs of each plant, Limerick was granted six formal exemptions from NRC regulations lasting beyond the first refueling compared to 10 for Susquehanna and 15 for LaSalle, as shown in Schedule 3.

Q. Since Limerick was so highly contested, is it also true that the NRC spent more time reviewing Limerick than other plants? If so, what is the significance of this added attention?

A. Yes, one can compare the number of licensing review hours expended on Limerick Unit 1 with the number of hours spent on other similar plants built in the same time frame. The number of hours spent by various organizations in the NRC (NRR, IE, the Regions, NMSS, and ACRS) from the CP stage through the granting of an OL is as follows:

FIRST UNITS WITH FULL POWER LICENSES

Plant	# NRC Review Hours
Grand Gulf 1	17,836
WNP 2	68,939
Susquehanna 1	52,489
LaSalle 1	70,632

In contrast, as of December 22, 1984, when Limerick still was awaiting an OL, the application had already consumed 82,949 NRC review hours. The excess review hours reflect the special treatment and extra stringent review given to the plant due to the high population density, the contested nature of the licensing process, and the resulting reluctance of the NRC to be flexible in its requirements. These extra hours were expended despite the fact that Limerick had the third shortest NRC licensing review and was the shortest of the contested cases of the 30 plants that received their Operating Licenses after the accident at Three Mile Island. The number of months between docket date and the low power license date was 39 months for Limerick, compared to 48 months for Susquehanna 1, and 59 months for LaSalle 1.

Q. Why was the license application for Limerick so highly contested?

A. The primary factor was the large population living near the plant. The NRC singled out three reactors during the early 1980's to conduct Probalistic Risk Assessments (PRA) to determine the risk associated with operating so close to major population centers. The other two plants were Indian Point and Zion. The population density within 50 miles of Limerick is approximately 6.9 million people, compared to 1.1 million for LaSalle and 1.5 million for Susquehanna. This issue became very visible, especially in the case of Indian Point, which had protracted hearings on the subject. It was because of the NRC's concern for controlling the potential risk for these areas of high population that it required a PRA and licensed Limerick strictly by the book. The hearing process also was more highly contested because of the high population density of Limerick, and this further increases the stringency of the NRC review.

Q. Are there any statistics that you could provide to help show that the hearings for Limerick were highly contested in comparison to LaSalle and Susquehanna?

A. The number of days spent in hearings is an excellent indicator of the degree of contention. Limerick spent 89 days in hearings compared to seven for

Susquehanna and none for LaSalle.

Q. Please explain the relationship between a contested hearing and the NRC's degree of prescriptiveness in the licensing process?

A. As I explained in earlier testimony before this Commission:

> I have observed that an OL case like Limerick with many intervening parties and many contentions, each alleging that Limerick fails to comply with NRC requirements, combined with the likelihood of many weeks of hearings extending over several years will cause the licensing process to become quite prescriptive. The NRC staff technical reviewers are less willing to accept departures from the Standard Review Plan, and the NRC regional inspectors are more likely to be narrow in their interpretations of inspection modules. Also the NRC staff management is less likely to defer open or confirmatory items in the review to later resolution; i.e., there will be fewer conditions allowed to be placed in the license. These effects are attributable to the hearing process. It is a natural tendency of the NRC staff and regional personnel, in preparing for contested hearings, to assemble the most defensible case they can present to the Atomic Safety and Licensing Board. The fewer departures from standard procedures and conditions that are allowed by the staff, the easier will be the defense against attack by intervenors in the proceeding. This in turn forces a utility to accept and implement prescriptive SRP criteria or other NRC requirements as a pre-requisite to issuance of an operating license. The end result is a cleaner license with fewer exceptions but higher costs to the utility. It has been my observation that this general situation prevailed in the case of Limerick, and this is borne out by the low power license which is relatively free of conditions in areas that have been troublesome to other recent license applicants.

Q. Mr. Mattson, are you aware that O'Brien-Kreitzberg & Asociates (OKA) and Dr. Hanauer have recognized the close interrelationship between public intervention and heightened NRC scrutiny, and the significant impact of these factors on nuclear project cost and schedule?

A. Yes. A report prepared by OKA on the San Onofre Nuclear Generation Stations Units 2 and 3, states:

> "The profound changes in technical requirements and licensing procedure that occurred during the 1970's interacted. Imposition of procedural delays and public intervention caused solving of technical problems to take longer, and increased the uncertainty in requirements in the meantime. Conversely, changing technical requirements increased the difficulty of finalizing the contested licensing decisions".

Preliminary Review of Construction and Management, prepared for the California Public Utilities Commission, p. 7-4 (May, 1983).

Similarly, a review of the Wm. H. Zimmer Nuclear Power Station, performed jointly by OKA and Dr. Hanauer, concluded:

> "Intervention in AEC and NRC quasi-judicial proceedings changed the character of the statutory public hearings from perfunctory review to hotly contested trials that required drastically increased time, resources, and management attention".

Analysis of Possible Mismanagement and Correlated Cost, Executive Summary, prepared for the Public Utilities Commission of Ohio (June, 1984).

Q. Mr. Mattson, has Dr. Hanauer acknowledged the necessity of considering plant unique factors in comparing nuclear plants?

A. Yes. In his cross-examination in Union Electric Company's Callaway proceeding, Dr. Hanauer stated:

> "...If you're comparing plant costs, then some site related aspects of plants might turn out to be very important...A very high seismic design...has a substantial cost impact on some of the systems in the plant and is a factor when comparing costs. Other possibilities are, at least one plant...in an area of relatively high population...was required to have special provisions limiting the containment leak rate in the event of an accident, and that was quite expensive."

Re Union Electric Company, Docket No. ER-84-168, Tr. 3508-3509 (1984).

Q. Do you have any data which might indicate a correlation between population density and plant costs?

A. Yes. While the factors affecting plant cost are complex, the data presented in Schedule 5 indicate that high population density around a nuclear plant, by eliciting greater regulatory prescriptiveness, increases the final total cost of a plant relative to plants in less populous locations. Schedule 5 provides a listing of the population density within 10 miles and the total cost per KW for 31 plants licensed or under construction since 1980, approximately the end of the licensing moratorium which resulted from the accident at Three Mile Island. These data show that the six plants, including Limerick, which are situated in high population density areas, have experienced plant costs significantly greater -- by over $1,000/KW -- than the average of plants located in less populous areas. This data confirms my personal judgment, made during many years in a nuclear regulatory capacity, that the licensing process experienced by nuclear plants is often reflected in their final total costs and is influenced by the population density around those plants.

Q. Dr. Mattson, can you provide any specific examples of the effect of population density and contested proceedings in causing significant differences in regulatory treatment of Limerick as compared to Susquehanna and LaSalle?

A. Yes, a number of specific examples can be provided as follows:

1. In Oversight Hearings before the Congressional Subcommittee on Energy and the Environment on May 27, 1980, Harold Denton, Director of the Office of Nuclear Regulation for the NRC described some significant regulatory changes that had taken place since the time PECo received its CP for Limerick in 1974. He stated that, after the mid-1970s, the NRC began to be more restrictive about allowable population densities around plant sites. Mr. Denton said that at the time Limerick received its CP, its population density fell within an "acceptable population envelope." However, circumstances after that changed dramatically and Harold Denton noted that: "[t]oday if any plant comes in with a population density in excess of 500 people per square mile, we conduct a very extensive search for alternatives." He went on to indicate that for plants with highly populated sites like Limerick, Zion, and Indian Point that had already received their CPs, additional design features were required to be considered that would not apply to plants located in more isolated areas.

2. An Advisory Committee on Reactor Safeguards (ACRS) memo of April 16, 1980, states another special requirement imposed on Limerick, as follows: "The ACRS believes that for those reactors at sites with higher population densities, additional considerations are appropriate. . . Limerick (accordingly) should be provided with a boron injection system having the reliability and reactivity reduction capability of [an alternative exceeding that required of other plants]."

3. In a letter dated August 10, 1971, the ACRS confirmed modifications that would be made to Limerick during its construction that were influenced by the high population density around the plant. These included a requirement to meet more stringent Class I seismic standards and other changes to the biological shield, emergency core cooling system, radioactive waste disposal system, recirculation pump trip, and hydrogen control. A detailed listing of special modifications required by the ACRS appears in its letter.

4. In a letter of May 6, 1980 from D. Eisenhut of the NRC to Mr. Bauer of PECO, the NRC requested that PECo perform a probabilistic risk assessment (PRA) study of the Limerick facility. At that time, the NRC had not decided how the Limerick PRA would be utilized in the licensing process, how it would be reviewed by the NRC, or what criteria would be applied to judge the adequacy of conclusions and recommendations that might be reached on the basis of the study. The only other reactors that were required to have PRAs were Zion and Indian Point. The fact that PECo was required to submit a PRA for its Limerick plant was significant in several respects. It was the first PRA performed for a BWR with a Mark II containment, the first required to be performed by a BWR owner, and the first to be relied upon in the operating license review. In addition, at the time Limerick's PRA was undertaken, there was no guidance from the NRC or others as to the acceptable scope, methods or data to be relied upon.

5. The number of contentions in the Limerick hearing owed in part to the high population density of the site. Contentions led to closure of some licensing issues on Limerick before full power licensing that were deferred on the other plants. These issues included environmental qualifications, TMI backfits, control room design review and radiological and meteorological monitoring system.

Q. What were the effects on construction of these special circumstances at Limerick?

A. There were a number of impacts on the design and the amount of material used in the construction process. For example, because of the higher population density, Limerick was required to provide an additional system for post-accident filtration. In addition, due to its higher population density and closer proximity to airports and railroads, more structural steel, concrete and rebar were required in safety-related structures at Limerick. Moreover, the AEC required that

Limerick's refueling area be designed to withstand these loads, thereby necessitating a thicker, reinforced concrete structure than was required at Susquehanna. Because of stricter seismic standards, a greater number of large pipe hangers was required at Limerick as well as substantially more ductwork and duct hangers. These effects of stricter regulatory requirements are addressed in detail and their effects are contrasted with circumstances existing at Susquehanna and LaSalle in the testimony of PECO witness David Helwig.

Q. Were there specific regulatory impediments to the completion of construction of Limerick 1 and the granting of an OL in July 1982?

A. Yes, there were. They are the engineering and licensing constraints described in the rebuttal testimony of PECO witnesses David Helwig and Edward Sproat. Also, the PRA and the licensing process were critical path items to OL receipt, not the Mark II containment as alleged by Dr. Hanauer.

Q. Dr. Mattson, please describe the NRC requirement changes to which you refer?

A. The primary engineering/licensing constraints encountered by PECo were associated with the following areas of change in NRC requirements:

1. Anticipated Transients Without Scram
2. Safety Parameter Display System
3. Environmental Qualifications
4. Control room human factors designs
5. Radiological and Meteorological Monitoring System
6. Fire protection
7. Various TMI Electrical Items

Because these items were all contested in the licensing hearings, the NRC required that they be completed before Limerick could receive its OL. In addition, the safety significance of these issues when taken as a group was sufficiently high that the NRC would likely have required that they be resolved before granting an OL, even if there had not been a contested hearing.

The ATWS issue was recommended to be completed prior to licensing as stated in the ACRS letter dated April 16, 1980, which I referenced earlier. In addition, PECO's Severe Accident Risk Assessment (SARA) showed that the risks of operating Limerick would only be acceptable if an ATWS solution were implemented, and the NRC required that the conclusions of SARA be implemented before licensing. PECo could not have speeded up its resolution of the ATWS issue because of the time taken by the NRC for reconsideration of what was required for ATWS after the TMI accident. In fact, the ATWS rulemaking for other plants did not come to its full generic conclusion until after the ATWS backfit had been fully implemented at Limerick.

Regarding equipment qualification, after the accident at TMI, reactors had to consider severe accident conditions as a part of the licensing basis. The ability of equipment to withstand severe accident environments was given special attention for reactors with small containments (such as Limerick, McGuire, and Sequoyah) and had an effect on the extent of completion required of the normal EQ programs, including mechanical equipment. Increased requirements for environmental qualification of electrical equipment had been the norm for plants licensed since about the time of TMI, but the degree of detail that the NRC Staff has required applicants to meet has grown steadily since that time depending upon the degree of intervention and the Commissioners expressed interests in minimizing exceptions. Moreover, the final definition of the staff's requirements has often been unclear until a detailed review has been performed. Evidence of this is provided in TVA's Sequoyah plant, which had to be shut down after only a few years of operation, in part because a detailed examination of electrical equipment qualification was not performed in the OL review. This was in marked contrast to the Limerick OL review where the high population density of the site and the high intervention in the hearing led to greater stringency and attention to detail by the NRC staff in the EQ and other areas, as I have described earlier.

As for the fire protection issue, NRC requirements changed frequently, and the Commissioners applied steadily increasing pressure in the early 1980s to force compliance with more prescriptive criteria before power operations.

The SPDS installation, the modifications to control room panels for human factors design, various TMI electrical items and the RMMS installation were all issues critically affected by the NRC's issuance of NUREG-0737 Supplement 1, which contained significant revisions of TMI-related requirements in these areas. This report was not issued by the NRC until January 1983. Similarly, the NRC guidance for mechanical equipment qualification was not provided to PECo until June 1982. The high population density of the site and the contentions of the hearing led to the need to complete these high priority TMI and EQ matters before licensing.

For all the above reasons, PECo could not have resolved these safety issues, which were prerequisite to licensing, any earlier.

Q. You mentioned that the Limerick Probabilistic Risk Assessment (PRA) and licensing generally were critical path items for operation of Limerick Unit 1. Can you elaborate?

A. An exhibit has been prepared to explain the effect of the development and licensing review of the PRA on the schedule for the NRC's issuance of a low power operating license for Limerick 1. It was developed jointly by the Company and myself, but subject to my supervision. The Exhibit (i.e., Exhibit RJM-1) provides a description of the various components comprising the NRC's licensing process and their interdependencies, expanding on the brief description contained in my direct testimony. The interaction between the NRC and the applicant during the application review process is described. The exhibit also describes in summary fashion the licensing process for Limerick 1. The NRC requirement for PECo to perform a PRA as a prerequisite to receipt of an OL is shown to be unique to Limerick.

The exhibit also describes the unique role the PRA played in the Limerick licensing process and provides background data as to events leading to NRC's request to perform a PRA. Factors influencing preparation of the PRA and the NRC review of the PRA are discussed, as well as litigation of the PRA before the Atomic Safety and Licensing Board.

In Exhibit RJM-1, there is developed an earliest possible schedule for low power licensing based on actual Limerick 1 experience. In conclusion, this Exhibit shows that preparation, review and litigation of the PRA were additional limiting activities on any accelerated path to low power licensing, and the licensing activities associated with the PRA could not have been accomplished sooner than mid-May, 1984.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

SCHEDULE 1

PERCENTAGE OF TOTAL ISSUES RESOLVED THROUGH LICENSE CONDITIONS

	Total Issues	Corresponding License Conditions	Percentage
Limerick #1	97	5	5
Susquehanna #1	109	22	20
LaSalle #1	29	12	41

Sources: NUREG-0991 and supplements for Limerick.
NUREG-0776 and supplements for Susquehanna.
NUREG-0519 and supplements for La Salle.

SCHEDULE 2

LICENSE CONDITIONS

	Limerick			LaSalle			Susquehanna		
	A	B	C	A	B	C	A	B	C
1. TMI	5	4	2	22	22	5	12	12	3
2. Fire Prot.	7	4	1	6	6	9	2	2	0
3. EQ	1	1	0	5	5	2	3	3	1
4. ATWS	0	0	0	0	0	0	0	0	0
5. Mark II	0	0	0	1	1	0	0	0	0
6. HELB	0	0	0	1	1	1	1	1	1
7. IE 79-14	0	0	0	0	0	0	0	0	0
8. Security	0	0	0	1	1	0	0	0	0
9. IEB 80-11	0	0	0	2	1	1	0	0	0
10. Seismic	0	0	0	2	2	1	4	4	1
11. Other	21	14	10	26	22	12	27	20	7
Total	34	23	13	66	61	26	49	42	13

COLUMNS REPRESENT THE FOLLOWING ITEMS:

Column A represents the total number of license conditions.

Column B represents the number of license conditions that remained to be completed before full power operation.

Column C represents the number of license conditions deferred beyond full power operation.

SOURCES: Operating License No. NPF-27 for the operation of Limerick #1, October 26, 1984.

Operating License No. NPF-11 for the operation of LaSalle #1, April 17, 1982.

Operating License No. NPF-14 for the operation of Susquehanna #1, July 17, 1982.

SCHEDULE 3

EXEMPTIONS FROM NRC REGULATIONS

Exemptions described in:	Limerick #1 D	Limerick #1 E	Limerick #1 F	Susquehanna #1 D	Susquehanna #1 E	Susquehanna #1 F	LaSalle #1 D	LaSalle #1 E	LaSalle #1 F
SER	4	4	3	9	4	4	12	12	12
SSER1	0	0	0	6	6	6	2	2	2
SSER2	1	1	0	0	0	0	2	2	2
SSER3	5	4	3	0	0	0	0	0	0
Oper. License	0	0	0	1	1	0	2	2	0
Total In License	10	9	6	11	11	10	18	18	15

D = Total exemptions
E = Total exemptions granted beyond 5% power
F = Total exemptions granted beyond first refueling

Sources: NUREG-0991 (with Supplements), Safety Evaluation Report Related to the Operation of the Limerick Generating Station, Units 1 and 2, August, 1983.

License No. NPF-27 for the operation of Limerick Unit #1, October 26, 1984.

NUREG-0519 with Supplements, Safety Evaluation Report Related to the Operation of LaSalle County Station, Units 1 and 2, June 1981.

License No. NPF-11 for the operation of LaSalle Unit #1, April 17, 1982.

NUREG-0776 with Supplements, Safety Evaluation Report Related to the Operation of Susquehanna Steam Electric Station, Units 1 and 2, April 1981.

License No. NPF-19 for the operation of Susquehanna Unit #1, July 17, 1982.

SCHEDULE 4

POPULATION DENSITIES
AROUND LIMERICK, LA SALLE, AND SUSQUEHANNA
IN MILLIONS OF PEOPLE

Distance in miles	Limerick 1980	LaSalle 1980	Susquehanna 1980
0-10	0.16	0.02	0.06
0-20	0.83	0.10	0.37
0-30	3.56	0.23	0.65
0-40	5.63	0.56	1.09
0-50	6.86	1.11	1.52

Sources: NUREG-0974 (for Limerick), Page 4-53, 4-54.

NUREG-0486 (for LaSalle), Page 2-2.

Pennsylvania Power and Light Company, Environmental Report for Susquehanna Steam Electric Plant, April, 1978.

SCHEDULE 5

COMPARISON OF POPULATION DENSITY AND COST FOR PLANTS LICENSED OR UNDER CONSTRUCTION SINCE TMI[1]

Plant	Population Within 10 Miles[2]	Plant Cost ($/KW)[3]
Limerick 1	152,644	3,014
Fermi 2	134,206	3,139
Millstone 3	105,619	3,326*
Beaver Valley 2	105,000	4,753*
Seabrook 1	79,478	3,965*
Perry 1	73,600	3,320*
Average for Plants with Populations greater than 70,000 within 10 miles	108,425	3,586
Average for Plants[4] with Populations less than 70,000 within 10 miles	23,168	2,238

Notes:

1. Plants entering commercial operation 1980 through 1989. Plants indicated with an asterisk are still under construction and their costs are subject to increase.

2. Source: Demographic Statistics Pertaining to Nuclear Power Reactor Sites, NUREG-0348, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, October 1979, Table 6. Statistics represent 1979 revision to data based on the year 1970.

3. Source: U.S. Nuclear Plants Cost per KW Report, Office of Engineering, Tennessee Valley Authority, September 1985. Costs include AFUDC.

4. Includes 25 plants with populations under 70,000 within 10 miles.