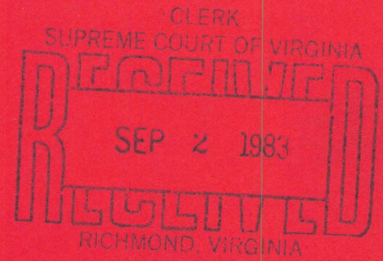


226 VA 541

SUPREME COURT OF VIRGINIA

Record No. 831040



VIRGINIA ELECTRIC AND POWER COMPANY,

Appellant,

v.

STATE CORPORATION COMMISSION AND
DIVISION OF CONSUMER COUNSEL OF THE
OFFICE OF THE ATTORNEY GENERAL

Appellees.

APPENDIX TO OPENING BRIEF
OF APPELLANT

Evans B. Brasfield
John W. Riely
Patricia M. Schwarzschild
Hunton & Williams
P. O. Box 1535
Richmond, VA 23212
Counsel for Appellant

TABLE OF CONTENTS

		<u>Page</u>
I.	Application of Virginia Electric and Power Company, filed 3/31/83-----	1
II.	Prefiled testimony and exhibits of Virginia Electric and Power Company, filed 3/31/83	
A.	William W. Berry pages 1 through 11; Appendix A-----	7
B.	Jack H. Ferguson page 7, line 15 through page 11, line 8; Appendix A-----	19
C.	B. D. Johnson page 1, line 1 through page 7, line 22; page 13, line 7 through page 20, line 23; page 21, line 15 through page 22, line 8; Appendix I; Exhibit Vepco-BDJ __, part 1, Schedule 1, Schedule 6, and Schedule 8-----	25
D.	O. James Peterson, III pages 1 through 12; Appendix I; Exhibit Vepco-OJP __, Schedules 1, 2, 3, 4, 5-1, 5-2, 5-3, and 6-----	55
E.	James P. Carney pages 1 through 23; Appendix A; Exhibit Vepco-JPC __, Attachments A, B, C, and D, and Schedules 1 through 15-----	77
F.	Eugene W. Meyer pages 1 through 30; Appendix A; Exhibit Vepco-EWM __, Schedule 1 through 8-----	130
III.	Interim Order of State Corporation Commission, dated 4/22/83-----	191
IV.	Petition for Reconsideration of Virginia Electric and Power Company, dated 4/27/83-----	207
V.	Order Suspending Filing Date of State Corporation Commission, dated 4/29/83-----	214
VI.	Order Disposing of Petition for Reconsideration of State Corporation Commission, dated 5/13/83-----	215
VII.	Motion for Suspension of Virginia Electric and Power Company, filed 5/23/83-----	223

	<u>Page</u>
VIII. Order Denying Motion for Suspension of State Corporation Commission, dated 6/24/83-----	225
IX. Petition for Appeal and Suspension and Motion for Expedited Appeal, filed 6/28/83, together with Exhibits A & B thereto-----	227
X. Assignments of Error filed by Virginia Electric and Power Company with the Court on 7/29/83-----	239

BEFORE THE
STATE CORPORATION COMMISSION
OF VIRGINIA

Application of)	
)	
VIRGINIA ELECTRIC AND POWER COMPANY)	Case No. PUE8300__
)	
For an Increase in Rates)	

APPLICATION

Virginia Electric and Power Company (Vepco or Company), One James River Plaza, Richmond, Virginia 23261 hereby applies for an increase in rates to take effect in two steps. The first step is an increase of \$44 million. This amount, which is an increase in total revenues of 2.5%, is an increase in base rates equivalent to the 3.87% increase in the Consumer Price Index in 1982. The Company requests that this amount be allowed to go into effect subject to refund on May 1, 1983 in order to reduce somewhat the continuing shortfall in the Company's earnings from Virginia jurisdictional customers below the level heretofore found by this Commission to be reasonable. As a second step, the Company requests an additional increase of \$131.2 million (7.3% of total revenues) and suggests that the Commission suspend this increase for 5 months so that it may take effect on August 29, 1983.

This Application is pursuant to the proposed Rules Governing Utility Rate Increase Applications published by the State Corporation Commission on August 31, 1982 in Case No. PUE820056 that the Commission has not adopted but has requested be used for rate applications. (Letter to William W. Berry, President,

Virginia Electric and Power Company from Hon. Preston C. Shannon, December 22, 1982)

In support of this Application, the Company states as follows:

1. The Company was allowed to increase its annual electric revenues on May 1, 1982 by an annual amount of \$80.5 million, subject to refund pending the Commission's consideration of the Company's Financial Operating Review in Case No. PUE820018. This increase was based on an equity return of 15% found reasonable by the Commission in the Company's most recent general rate proceeding, Case No. PUE810025, and an allowed overall rate of return of 10.88%. The Commission, in its August 30, 1982 Final Order, reduced that annual increase slightly to \$80.4 million, and based that decision on an authorized equity return of 15% and an overall rate of return of 10.88% for the 1981 test year.

2. The Company earned for the test year ended December 31, 1982, after annualizing the effect of the rate increase granted in 1982 and after other appropriate adjustments, an overall rate of return of 8.61%, substantially below the 10.54% based on the equity return of 15% authorized by the Commission in Case No. PUE820018 and the embedded cost of senior capital at the end of 1982.

3. The Commission last considered the Company's required return on equity in Case No. PUE810025 and found that the reasonable return on common equity for Vepco was between 15% and 15.5% but based the Company's rates on a 15% return on equity because the performance of certain of Vepco's generating units was perceived to be less than satisfactory (Final Order,

Application of Virginia Electric and Power Company, Case No.

PUE810025, mimeo at 8-9 (August 24, 1981)). The performance of the generating units has materially improved and a reduction in the allowed return on common equity can no longer be justified.

4. Cost of capital to the Company has increased since Case No. PUE810025, with the cost of common equity now being in the range of 15.5% to 16.5%. The increase requested in this proceeding is based on an equity return of 16%. This rate of return on common equity results in a required overall rate of return to the Company of 10.87%, and this, along with other cost of service items, is the basis of the Company's requested increase in rates.

5. The cancellation of North Anna Unit 3 is an additional matter included in the Company's Application that requires special mention. The Company is requesting additional revenues of \$26.9 million or a 1.5% increase in annual revenues to cover the write-off of this investment over 10 years and an appropriate return on the unamortized balance. After the completion in the fall of 1982 of a new detailed cost estimate of North Anna Unit 3, it became clear that huge increases in the cost of this unit made it no longer economically justified. These new estimates incorporating regulatory changes through the time of the estimates showed total costs for the 907 megawatt unit of between \$4.1 and \$5.1 billion (depending on the date of expected commercial operation), twice the level of previously estimated costs. Completion of North Anna Unit 3 would have required an investment by 1990 of roughly one-third of the Company's total assets in a unit that would have represented less than 10% of its

total generating capacity. The Company can obtain its required generating capacity from other sources at substantially lower cost. The cancellation of the unit was thus prudent and timely. The Company has, in its calculation of the revenue requirement attributable to the cancellation of North Ann Unit 3, levelized it over the period of the write-off. This substantially reduces the present revenue requirement attributable to that return and thereby reduces the impact on customers. The dollars invested in North Anna Unit 3 were, at the time when the investment was made, prudently invested for the purpose of furnishing public utility service to the Company's customers. The Company's proposal for amortization of the investment and return on the unamortized portion should therefore be accepted.

6. The Company's request that \$44 million of the proposed increase in revenues be allowed to go into effect on May 1, 1983 is consistent with existing Commission practice as to ratemaking procedures for expedited increases, and it does not involve any change in the Company's existing approved rate design. This expedited increase would be limited to an increase in base rates on the Company's 1982 jurisdictional booked base rate revenues of 3.87%, which was the 1982 increase in the Consumer Price Index. An annual increase in this amount (\$44 million) would produce a pro forma rate of return of only 9.13%, still significantly below 10.54% (the return calculated using the previously authorized 15% return on common equity and the 1982 year end cost of senior capital). If the Commission allows this portion of the rate increase to go into effect in accordance with its expedited rate procedures, the deficiency in rate of return that the Company

is now experiencing will be somewhat mitigated. Rate schedules to accomplish this expedited revenue increase are filed herewith in Schedule 32, and it is these schedules that the Commission is asked to put in effect subject to refund on May 1, 1983. Schedule 32 also includes the rates for which ultimate approval, after a hearing, is sought.

7. The Appendix to this Application includes the schedules required by the guidelines contained in the proposed Rules Governing Utility Rate Increase Applications. Certain of the schedules in the Appendix are also offered as exhibits accompanying the Company's prepared direct testimony which is submitted with this Application.

8. All correspondence to Vepco concerning this Application should be addressed to:

E. Paul Hilton
17th Floor
One James River Plaza
P.O. Box 26666
Richmond, Virginia 23261

and

Evans B. Brasfield, Esq.
Hunton & Williams
P.O. Box 1535
Richmond, Virginia 23212.

WHEREFORE, the Company, pursuant to Va. Code Title 56, Chapter 10, requests the Commission to allow an interim rate increase of \$44 million and the proposed rate schedules filed in connection therewith to go into effect with respect to service rendered on and after May 1, 1983, subject to subsequent investigation and possible refund, and to approve an additional rate increase of \$131.2 million and allow the proposed rate

schedules filed in connection therewith to take effect, after the requested suspension period, with respect to service rendered on and after August 29, 1983.

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By: Evans B. Brasfield
Counsel

DATED: March 31, 1983

John W. Riely
Evans B. Brasfield
Richard D. Gary
Patricia M. Schwarzschild
HUNTON & WILLIAMS
P. O. Box 1535
Richmond, Virginia 23212

TESTIMONY OF WILLIAM W. BERRY
FOR
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE8300 29

Q. Please state your name, business address and position with Virginia Electric and Power Company.

A. My name is William W. Berry, and my business address is One James River Plaza, Richmond, Virginia. I am President and Chief Executive Officer of Virginia Electric and Power Company.

Q. Mr. Berry, have you previously testified before this Commission?

A. Yes. I have testified before this Commission on numerous occasions in a variety of proceedings. A summary of my background and qualifications is included as Appendix A to my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the nature of the rate relief requested in this proceeding and, in so doing, highlight a number of the major events initiated by the Company or impacting on its operations.

Q. Mr. Berry, please describe the Company's rate increase proposed in this application.

A. In the 1982 test year the Company earned a rate of return, as shown by the testimony of B. D. Johnson, of 8.61% on its Virginia jurisdictional rate base after taking into account

appropriate ratemaking adjustments. This was significantly below the rate of return of 10.54% based on the rate of return on common equity last authorized by the Commission (15%) and the embedded cost of senior capital at the end of 1982. The Company is requesting a two-step increase in rates of \$44 million (2.5%) and \$131.2 million (7.3%) on an annual basis to halt this deficiency and to give an opportunity to earn an overall rate of return of 10.87% (based on 16% return on common equity).

Our Application requests that the initial increase of \$44 million be allowed to go into effect on May 1, 1983, subject to refund, in order to minimize somewhat the continuing deficiency in the Company's earnings, and that the increase of \$131.2 million be suspended by the Commission for 5 months and become effective for service rendered on and after August 29, 1983. The first increase has been calculated in accordance with existing Commission practice as to ratemaking procedures for expedited increases, and it does not involve any change of the Company's existing approved rate design. This expedited increase would be limited to an increase in base rates of 3.87%, which was the 1982 increase in the Consumer Price Index. An increase in this amount (\$44 million) would, as shown by the testimony of B. D. Johnson, produce a pro forma rate of return of only 9.13%, which is still below the previously authorized overall rate of return and the Company's present cost of capital. By allowing this portion

1 of the increase to go into effect on May 1, 1983 with a
2 refund obligation, the Company's earnings shortfall will be
3 mitigated somewhat, and rates will be at a level that
4 certainly is clearly justifiable.

5 Q. Mr. Berry, are there any components of the Company's request
6 that you would like to comment on specifically?

7 A. Yes. There are two items that deserve special mention. The
8 first such item involves the cancellation of North Anna Unit
9 3. We are requesting additional annual revenues of
10 \$26.9 million, or a 1.5% increase in annual revenues, to
11 cover the write-off of this investment over 10 years and an
12 appropriate return on the unamortized balance.

13 After the completion in the fall of 1982 of a new
14 detailed estimate of the costs of North Anna Unit 3, it
15 became clear that huge cost increases had caused the unit to
16 be no longer economically justified. The new estimate of
17 the costs of the unit, incorporating regulatory changes
18 through the time of the estimate, showed total costs for the
19 907 megawatt unit of between \$4.1 and \$5.1 billion
20 (depending on the date of expected commercial operation) -
21 twice the level of previous estimates. Completion of North
22 Anna Unit 3 would have required an investment by 1990 of
23 roughly a third of the Company's total assets in a unit that
24 would have represented less than 10 percent of Vepco's total
25 generating capacity. Given the level of the new estimate,
26 it became clear to us that cancellation will:
27

- 1 - keep electric rates to Vepco's customers lower
- 2 than they would have been if the unit was
- 3 completed;
- 4 - allow the continuation of reliable electric
- 5 service through the timely purchase of more
- 6 economical capacity;
- 7 - avoid an unsustainable financing requirement and a
- 8 further downrating of Vepco's debt securities; and
- 9 - eliminate significant economic risks associated
- 10 with the development and operation of North Anna
- 11 Unit 3.

12 You will recall that in November 1980, after an
13 intensive re-examination of the plans to build North Anna
14 Units 3 and 4, Vepco cancelled North Anna Unit 4. Also at
15 that time we concluded that, based on the information
16 available, North Anna Unit 3 should not be cancelled but
17 recognized that the situation might change. Thus, we
18 decided in 1980 to proceed cautiously with North Anna Unit
19 3, while continuing to evaluate that decision in light of
20 changes in regulatory and financial conditions. We then
21 began to perform the detailed design and engineering
22 required to complete the unit as soon as possible, but
23 withheld any major construction expenditures until the new
24 cost estimates based upon the engineering work could be
25 evaluated. The new cost estimates, to which I have
26 referred, would result in capacity costs ranging from about
27 \$4,500 to \$5,600 per kilowatt installed. At these costs,

1 completing North Anna Unit 3 would no longer be the least
2 costly alternative available to Vepco for meeting future
3 electric needs.

4 This matter is covered in greater detail in the
5 testimony of Jack H. Ferguson.

6 Q. Is your request with respect to the ratemaking treatment of
7 the cancellation of North Anna Unit 3 the same as the
8 Company's previous requests with respect to Surry Units 3
9 and 4 and North Anna Unit 4?

10 A. Yes, with one important exception. While we are requesting
11 a write-off of the investment over ten years and a return on
12 the unamortized balance, we have calculated the return in a
13 manner that benefits customers in two ways. First, we have
14 calculated the return using the actual 1982 return on equity
15 of 10.1% rather than our requested equity return of 16%,
16 since we do not believe we should ask customers to pay a
17 higher return on a cancelled project than they paid before
18 it was cancelled. Second, we have levelized the amortiza-
19 tion and return over the period of the write-off, which
20 substantially reduces the present revenue requirement
21 attributable to that return, and thus minimizes the impact
22 on customers.

23 With the changes we have made the revenue requirement
24 attributable to the cancellation of North Anna 3 is only a
25 \$3.6 million increase above the 1983 revenue requirement if
26 construction of the unit had been continued, and in future
27 years the revenue requirement attributable to cancellation

1 will be less than the revenue requirement for continued
2 construction.

3 B. D. Johnson will testify in more detail on how the
4 return component has been calculated. What I want to
5 emphasize is the importance and appropriateness of a return
6 allowance. The dollars invested in North Anna Unit 3 were,
7 at the time the investment was made, prudently invested for
8 the purpose of furnishing public utility service to our
9 customers. The Commission has found this to be the case in
10 the previous cases allowing the write-off of the investment,
11 but has, we believe, taken action inconsistent with this
12 finding by denying recovery of the costs of financing that
13 investment. Moreover, now that the Company can obtain other
14 generation at a lower cost, the cancellation of North Anna
15 Unit 3 was required to assure the availability to our
16 customers of the most economical sources of generation. We
17 have calculated the return requirement in a manner that will
18 minimize the impact on customers, and we strongly urge the
19 Commission to allow this item in this instance.

20 Q. What is the other cost of service item that you will
21 discuss?

22 A. The second item I will discuss is the need for an increase
23 in the Company's allowed return on common equity.
24 For the last two years the Company has been penalized 50
25 basis points on equity because of generating unit
26 performance in 1980 that the Commission found to be
27 unsatisfactory. Such performance has improved remarkably

1 since then, and this should be recognized by the Commission
2 and the penalty to return on equity should be removed.

3 As Mr. Ferguson will testify in greater detail, the
4 capacity factor of our nuclear units increased from 49.2% in
5 1980 to 60.2% in 1982, an increase of 22.4%. The equivalent
6 availability factors of the Company's five large coal-fired
7 units increased from 42.6% in 1980 to 63.8% in 1982, an
8 increase of 49.8%. During 1982 our nuclear units generated
9 41% of our total energy supply and coal 37%, up from 27.0%
10 and 25.4%, respectively, in 1980, which equate to increases
11 of 51.9% and 45.7%, respectively. In addition, as shown on
12 Mr. Ferguson's Exhibit Vepco - JHF __, Schedule 3, the heat
13 rates achieved by the system's fossil generation have
14 improved significantly. Despite an extended outage of North
15 Anna Unit 1 in 1982, generating performance for the year was
16 excellent, and the Company ranked second among
17 investor-owned utilities in generation of electrical energy
18 by nuclear power. We believe Vepco is entitled to
19 recognition of this in its allowed return on common equity.

20 In determining what allowance should be made for a
21 return on common equity, the Commission should finally take
22 note of a reality that has been one of the major causes of
23 the Company's inability to earn its cost of capital in
24 recent years. That reality is that, despite the
25 Commission's allowance of a year-end rate base and pro forma
26 adjustments for known changes, the combination of inflation
27 and regulatory lag has absolutely prohibited the Company

1 from earning the rate of return that has been approved.
2 The testimony of both James P. Carney and O. J. Peterson
3 will show that year after year, when the Commission has
4 approved a rate of return without any specific allowance for
5 attrition, the Company's earned rate of return has fallen
6 short of what was approved by a wide margin. This has
7 happened over the years despite changes in the economy,
8 changes in management and improvements in efficiency. It
9 has happened not only for Vepco, but for other companies in
10 jurisdictions where there is not any specific attrition
11 allowance or use of a fully projected test year.

12 The time has come, we believe, for the Commission to
13 recognize that the deficiency in rate of return cannot in
14 most cases be attributed to inefficient management or
15 unforeseeable bad luck; it must be attributed to the failure
16 of this and other commissions to acknowledge, on the basis
17 of what has happened in prior years, that attrition does
18 exist even in the best managed utilities and it must be
19 taken into account if utilities are to earn what the
20 Commission finds to be their cost of capital.

21 Accordingly Mr. Carney, Vepco's Director-Economic
22 Analysis, has, in his rate of return calculation, made a
23 modest first step to deal with attrition by including a
24 small attrition allowance in determining that the Company's
25 cost of common equity is in the range of 15.5% to 16.5%.
26 Our request is based on 16%. In light of our improved
27

1 generating performance and our experience with attrition,
2 this rate of return is entirely justified and we urge the
3 Commission to approve it. Such action by the Commission
4 would enhance greatly our ability to raise, on terms
5 beneficial to our customers, the large amounts of capital
6 that the Company will require in the next several years.

7 Q. What are those capital requirements?

8 A. Our construction program will involve expenditures of
9 approximately \$2.2 billion during the three-year period
10 1983-85 and \$3.5 billion during the five-year period
11 1983-87. Much of this sum will have to be raised through
12 the sale of the Company's securities, and a strong financial
13 condition and good prospects for reasonable earnings are
14 essential if this capital is to be raised on favorable
15 terms. While our projected growth in demand is
16 substantially lower than a few years ago (presently
17 estimated to be 2.1% per year in the summer and 3% per year
18 in the winter), the construction necessary to meet even that
19 level of growth and to extend electric service to new
20 construction in our service area will require the large
21 amounts of capital I have mentioned.

22 Q. What are the principal components of the Company's capital
23 requirements?

24 A. The principal components are the Company's Bath County
25 Pumped Storage Project, improvements in existing generating
26 facilities, distribution facilities to bring service to new
27 customers, and a variety of smaller capital expenditures

1 such as upgrading transmission and general plant facilities
2 and investments in nuclear fuel.

3 The estimated \$2.2 billion and \$3.5 billion required
4 are greatly reduced from what they might have been. The
5 Company has taken major measures to reduce its capital
6 requirements. As the Commission is aware, we have reached
7 agreement with Allegheny Power System to sell a portion of
8 our Bath County Pumped Storage Project. That Project is
9 scheduled for completion in 1985-86. In addition, the
10 Company has signed, and requested the Commission to approve,
11 an arrangement with Old Dominion Electric Cooperative for
12 the sale of a portion of Vepco's North Anna station.

13 Q. Has the Company been looking at other means of reducing its
14 construction expenditures in the future?

15 A. Yes. In November 1981, we announced a three-year study of a
16 dozen non-conventional means of meeting future load growth.
17 These include conservation, load management, cogeneration,
18 solar energy applications in homes and businesses, low-head
19 hydroelectric power, municipal waste burning, wood burning,
20 peat burning, wind turbines, fuel cells, combined cycle
21 systems and solar photovoltaic cells. These means of
22 producing electricity and controlling growth in demand will
23 be compared with each other and with conventional generation
24 options to determine the most economical and practical means
25 of meeting future load growth.

17

1 Through these steps and others that will follow Vepco
2 will analyze many ways--conventional and unconventional--to
3 reduce our capital requirements. But the construction
4 program that we must continue is large, and our oil-to-coal
5 conversion program and fossil unit performance improvement
6 program require substantial capital. Ultimately, the
7 success of our efforts to raise the needed capital through
8 the sale of our securities depends on adequate rate relief
9 and earnings that will attract investors.

10 Q. Are there any concluding comments that you would like to
11 make?

12 A. Yes. As I stated last year, the Company has shifted its
13 focus from a massive construction program to an
14 operations-oriented strategy. The improvements in
15 generation mix and unit performance that I have mentioned
16 are a direct result of this shift in strategy.

17 We are proud of these improvements but we are not
18 content to stop there. Our recently-announced corporate
19 reorganization has the same objectives: improved managerial
20 efficiency to assure good service at reasonable rates,
21 improved earnings and strengthened financial conditions.

22 We are committed to these goals, and we believe the
23 Commission, in the public interest, should also be committed
24 to them. Approval of our requested rate increase would be
25 consistent with that commitment, and we respectfully urge
26 the Commission to grant that approval.

27

QUALIFICATIONS OF WILLIAM W. BERRY

Mr. William W. Berry graduated from Virginia Military Institute in 1954 with a Bachelor of Science degree in electrical engineering. In 1964 he received a Master of Commerce degree from the University of Richmond. He also is a registered professional engineer in the State of Virginia. Since joining Vepco in 1957 he has held various positions in the Company's Power Production Department including Station Superintendent at the Portsmouth Power Station and Superintendent - Power Supply Operations. He was appointed Executive Director of the 1973 reorganization. In January 1974 he was elected Vice President - Commercial Operations. In January 1978 he was elected Executive Vice President. He became President and Chief Operating Officer and was elected to the Board of Directors May 1980. He became President and Chief Executive Officer on January 1, 1983.

Mr. Berry has testified before this Commission and before the North Carolina Utilities Commission, the Public Service Commission of West Virginia and the Federal Energy Regulatory Commission.

TESTIMONY OF JACK H. FERGUSON
FOR VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE VIRGINIA COMMISSION
CASE NO.

4 net savings of approximately \$500 million as a result
5 of the coal conversions and fossil unit improvement
6 program.

7 Our Bath County Pumped Storage Project is pro-
8 gressing smoothly with three of the units planned to
9 come on-line in October 1985 and the remaining three in
10 October 1986. Construction costs are estimated to
11 total approximately \$400 million from 1982 through
12 1985. The total cost of the Bath County Project will
13 be approximately \$1.6 billion when completed.

14
15 Q. Mr. Ferguson, please discuss the cancellation of North
16 Anna Unit 3.

17 A. In November 1982, the decision was made to cancel North
18 Anna Unit 3. This decision was based on months of
19 detailed and thorough evaluations regarding estimated
20 completion cost increases for North Anna Unit 3.

21 In light of the new cost estimates for North Anna Unit
22 3 reflecting these cost increases and other develop-
23 ments, completing the unit was no longer the least
24 costly alternative available to Vepco for meeting
25 future electric needs.

20

1 Q. What alternatives to North Anna Unit 3 is Vepco now
2 pursuing?

3 A. The cancellation of North Anna Unit 3 did not result
4 from any reduction in Vepco's forecast for load growth.
5 Therefore, the capacity which would have been supplied
6 by North Anna Unit 3 will have to be replaced from
7 other sources. Accordingly, a formal task force has
8 been established to investigate potential purchase of
9 capacity or purchase of assets from other utilities.
10 Our initial investigation showed that many of our
11 neighboring utility systems have excess capacity for
12 sale on a long term basis at economical prices.
13 Presently we are discussing and evaluating several
14 specific combinations of asset purchases and/or long
15 term capacity purchase with these utilities. Vepco is
16 committed to acquiring the capacity required to provide
17 reliable service. In addition to these planned pur-
18 chases, the development of conservation and load
19 management techniques and the implementation of cogen-
20 eration and non-conventional generating methods will
21 also contribute to replacement of the capacity planned
22 from North Anna Unit 3.

23

24 Q. Mr. Ferguson, you mentioned that a detailed and thor-
25 ough evaluation regarding estimated completion costs of
26 North Anna Unit 3 was performed, please elaborate.

1 A. The first task in performing the estimate was begun in
2 early 1981 with a detailed review of existing engineer-
3 ing in light of the myriad of new regulations promul-
4 gated in the wake of the Three Mile Island (TMI)
5 accident to determine what was still valid, what had to
6 be redone and what would be required to complete the
7 project. This involved detailed analysis of over 2,000
8 drawings and specifications and thousands of design
9 calculations. Concurrent with the review, it was
10 necessary to perform at least preliminary redesign to
11 determine what would be required for compliance with
12 the new requirements. These two activities involved
13 some 200 engineers and support personnel and required
14 16 months to complete.

15 As the results of the design review became avail-
16 able, planners, schedulers and cost estimators began to
17 assemble the associated costs and schedules for pro-
18 curement, construction and startup. Bechtel Power
19 Corporation - one of the leading contracting firms in
20 the nuclear industry - was retained by Vepco to make an
21 independent estimate of the costs of North Anna Unit 3.
22 This required identification of every unit of work -
23 every cubic yard of concrete, foot of pipe, foot of
24 cable - for millions of individual units. Four months
25 of intensive effort were required before sufficient
26 information was available to make a detailed reestimate
27 of project cost. The new estimates for North Anna Unit

1 3 showed total costs between \$4.1 and \$5.1 billion,
2 depending on the expected year of completion of the
3 unit. This estimate is significantly higher than
4 previous estimates, and is in the range of \$4470 to
5 \$5600 per kilowatt installed.

6

7 Q. Mr. Ferguson, what caused the cost of the plant to
8 increase so substantially?

9 A. The sharp increase in total costs is largely attribut-
10 able to the similarly sharp increase in regulatory
11 requirements since TMI. Because of the number and
12 complexity of the new regulations, and because of
13 uncertainty as to their interpretation by the Nuclear
14 Regulatory Commission, the impact of the new regu-
15 lations was not fully appreciated until 1982. It is
16 now clear that the impact is very large. Well over
17 half of the total increase in costs from the previous
18 estimate is directly attributable to increased regula-
19 tory requirements.

20

21 Q. Please summarize your testimony.

22 A. Our nuclear units are continuing to perform well and
23 account for over 40 percent of our total generation.
24 We are continuing our oil-to-coal conversion program
25 and our fossil unit improvement program. The perform-
26 ance of Vepco's fossil units continues to improve. Our
27 Bath County Pumped Storage Project is on schedule and

1 should begin operation in 1985 and 1986. Finally, I
2 discussed certain aspects of the decision to cancel
3 North Anna Unit 3. As a result of regulatory changes,
4 the estimated construction costs of the unit increased
5 so greatly that it was no longer the least costly
6 alternative available to Vepco to meet the needs of our
7 customers. Therefore cancellation of the unit was a
8 necessary and prudent decision.

9
10 ~~Q. Mr. Ferguson, does this conclude your pre-filed testi-~~
11 ~~mony?~~

12 ~~A. Yes, it does.~~

BACKGROUND AND QUALIFICATIONS
OF
JACK H. FERGUSON

I received a B.S. Degree in Mechanical Engineering from Colorado State University in 1960.

After graduating in 1960, I joined the General Electric Company and performed various technical assignments at the Atomic Energy Commission Hanford Facilities. Following that I was given successive assignments as Manager - BWR Simulator Project, Start-up/Site Manager of the Tsuruga Nuclear Project in Japan and Project Manager, Nuclenor Nuclear Project in Spain.

I later joined the Daniel Construction Company in Greenville, South Carolina, as Manager of Technical Services. After a brief association with Daniel Construction Company, I joined the Westinghouse Electric Corporation as Manager, Kori Nuclear Project in Korea and later as Manager, Far East Projects with nuclear, fossil, and associated projects in Korea, Japan, and Indonesia.

In April 1974, I returned to the United States and became Vice President of the Energy Division of J. A. Jones Construction Company in Charlotte, North Carolina, with responsibility for all nuclear, fossil, and power related projects in the U. S. and overseas. In June, 1979 I joined Houston Lighting and Power where I served as a consultant. On December 21, 1979, I was elected Executive Vice President - Power, Virginia Electric and Power Company. I served in that position until January 1, 1983. On January 1, 1983. I assumed my present position as Executive Vice President and Chief Operating Officer.

FOR VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE
THE STATE CORPORATION COMMISSION OF VIRGINIA

CASE NO. PUE 83 0029

1 Q. Please state your name, position, and responsibilities of that position.

2 A. My name is B. D. Johnson and I am Vice President and Controller of
3 Virginia Electric and Power Company. I am the principal accounting
4 officer and responsible for all accounting operations which include
5 the General, Payroll, Property, and Customer Accounting Depart-
6 ments. In addition, my duties include responsibility for taxes,
7 depreciation, regulatory services, and corporate budgeting. A state-
8 ment of my background and qualifications is presented in Appendix I
9 to this testimony.

10

11 Q. What is the purpose of your testimony?

12 A. My testimony covers the calculation of the revenue requirement that
13 the Company is presenting in this proceeding, based on the test year
14 ended December 31, 1982. In presenting such evidence, certain rate-
15 making adjustments are made which include: (1) annualization of the
16 new rates which became effective August 30, 1982 in Case No.
17 PUE820018; (2) the continued gradual elimination of Allowance for
18 Funds Used During Construction (AFUDC) related to all new projects
19 for which construction began after August 31, 1981; (3) the effect of
20 the cancellation of North Anna Unit 3; (4) the effect of the load loss
21 related to the new Southeastern Power Agency (SEPA) contract
22 effective December 30, 1982 and North Carolina municipals; (5) the
23 effect on Federal income taxes of interest synchronization; (6) an
24 adjustment to eliminate the AFUDC attributable to North Anna Unit
25 3 during the test period and the 20% portion of Bath County that was

1 sold in 1982 and; (7) an adjustment for a second 20% of the Bath
2 County Project with respect to which Allegheny Power System (APS)
3 is obligated either to buy the assets or take the capacity for a ten-
4 year period. Other adjustments similar in principle to ones previously
5 approved by the Commission have likewise been made.

6

7 Q. Will you present an exhibit in the course of your testimony?

8 A. Yes. I have an exhibit in two parts with numerous schedules prepared
9 under my supervision, and it is correct to the best of my knowledge
10 and belief.

11

12 Q. Mr. Johnson, what is the additional annual revenue requirement
13 sought by the Company in this proceeding?

14 A. The Company is seeking additional annual revenue of \$175.2 million
15 comprised of the following major components:

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1	<u>DESCRIPTION</u>	<u>REVENUE REQUIREMENT</u> (millions of dollars)
2		
3	1. Shortfall as of December 31, 1982, based on 10.54 percent cost of capital including 15 percent return on common equity. (Assumes North Anna Unit 3 in rate base.)	\$ 68.2
4		
5		
6	2. Effect of the cancellation of North Anna Unit 3.	26.9
7		
8	3. Increase return on equity from 15 percent to 16 percent.	28.1
9	4. Elimination of AFUDC attributable to nuclear fuel and new projects started after August 31, 1981.	9.4
10		
11	5. Reallocation of capacity for North Carolina municipal customer load loss and the new SEPA contract.	9.6
12		
13	6. Interest synchronization for Federal income tax purposes.	32.0
14		
15	7. Eliminate AFUDC from test period for 20% portion of Bath County Project sold to APS.	5.0
16		
17	8. Removal of second 20% of Bath County Project dedicated to APS.	(8.9)
18	9. Other.	4.9
19	Total	<u>\$175.2</u>
20		
21		
22		
23		
24		
25		

1 Q. Mr. Johnson, how does the Company propose to implement the
2 increase requested?

3 A. As outlined by Mr. Berry in his testimony, the Company is requesting
4 the additional revenue in two steps:

5 Step One includes an amount of \$44.0 million which the
6 Company requests to be made effective May 1, 1983. This amount
7 has been calculated in Mr. Hostetler's testimony in accordance with
8 guidelines included in the Commission's proposed "Revised Rules
9 Governing Financial Operating Revenue and Utility Rate Case
10 Filings," Attachment A, Rule II, Item (4), which permits an expedited
11 increase in rates so long as such increase does not exceed the
12 Consumer Price Index (CPI) calculated in the manner provided in
13 Schedule 36 of the Appendix to those revised rules.

14 The Company, however, in its comments on the Commission's
15 proposed Revised Rules in Case No. PUE820056 and in its Exceptions
16 to the Report of the Hearing Examiner in Case NO. PUE820018, has
17 argued that the CPI should be applied to test year sales of electricity
18 annualized to reflect rate increases approved during the year, rather
19 than applied to unadjusted booked revenues as required in the
20 proposed Revised Rules. This continues to be the Company's position,
21 on which the Commission has not yet ruled. The Company has
22 calculated the CPI limit pursuant to Schedule 36 of the Revised Rules
23 without annualizing test year revenues in this case. It did so,
24 however, only because the Commission's proposed Revised Rules,
25 which have not been adopted, expressly require it and the

1 Commission has directed that they be used in this case pending
2 consideration of their adoption.

3 The Company's position on this matter, which is stated more
4 fully in Case Nos. PUE820018 and PUE820056, is that since the
5 increase in rates that is limited by the CPI is an annualized amount,
6 the revenues on which that limit is based must likewise be an
7 annualized amount. Otherwise the amount of an allowable rate
8 increase in one year would be determined in part by when in the
9 previous year the commission allowed a rate increase to go into
10 effect. If we had used the Company's method of determining the CPI
11 limit in this case, we would be asking for an expedited increase of
12 \$45.3 million rather than \$44.0 million. By asking for the lesser
13 amount now, the Company does not withdraw its objections to
14 Schedule 36 nor waive its right to ask the Commission to establish
15 that the CPI percentage increase should be applied to annualized test
16 year revenues.

17 Step Two involves an amount of \$131.2 million, the difference
18 between the total revenue requirement sought of \$175.2 million and
19 the amount sought in Step One, \$44.0 million. The Company requests
20 that this \$131.2 million go into effect after suspension on August 29,
21 1983.

22
23 Q. Mr. Johnson, do you have an exhibit that shows the rate of return
24 from the Company's Virginia jurisdictional service and a calculation
25 of the additional annual revenue requirement sought in this

1 proceeding?

2 A. Yes, Exhibit VEPCO-BDJ ____, Part 1, Schedule 1, presents that
3 information for the twelve months ended December 31, 1982, the test
4 period in this proceeding.

5

6 Q. What does this schedule show?

7 A. Schedule 1, Page 1, shows net operating income, rate base and rate of
8 return for the Company's electric system (Columns A - C) and its
9 Virginia jurisdictional service (Columns D -H). The schedule shows
10 the necessary adjustments, the calculation of adjusted and pro forma
11 rates of return, and the additional revenues requested.

12

13 Q. What is the system electric rate of return for the 12 months ended
14 December 31, 1982?

15 A. Line 50 of Column A shows that the system electric rate of return
16 per books is 9.57%, and that when the appropriate system electric tax
17 adjustments are made the system electric rate of return shown in
18 Column C remains 9.57%.

19 Column B of Schedule 1 shows the various tax adjustments to
20 which I have just referred. They are detailed on Schedule 1, Page 2
21 in two categories: (1) adjustments necessary to eliminate from the
22 book provision the effect of prior period items, and (2) certain
23 adjustments to the book provision necessary to adjust estimated
24 amounts to actual. These adjustments are identical in principle to
25 adjustments approved by the Commission in previous rate

1 proceedings.

2

3 Q. Mr. Johnson, Columns D through H of Schedule 1, Page 1, of Exhibit
4 VEPCO-BDJ ____, Part 1, are headed Virginia jurisdictional service.
5 How were the figures in Column D derived?

6 A. The Accounting Department furnished to Mr. H. H. Dunston, Jr.,
7 Manager - Cost Analysis, the system figures shown in Column C. Mr.
8 Dunston then made the allocation to Virginia jurisdictional service.
9 This allocation process is discussed in Mr. Dunston's testimony.

10

11 Q. What is the Virginia jurisdictional rate of return prior to rate-making
12 adjustments?

13 A. Column D, Line 33 shows net operating income of \$451,095,000 and
14 Line 49 shows the rate base of \$4,459,172,000, resulting in an
15 unadjusted rate of return from Virginia jurisdictional business for the
16 12 months ended December 31, 1982, of 10.12% as shown on Line 50.

17

18 Q. Would you please identify the adjustments shown in Column E of
19 Schedule 1, Page 1?

20 A. The adjustments in Column E of Page 1 are shown in detail on Page
21 3A and B of Schedule 1, Columns A through J with further detailed
22 references to Schedules 2 through 9.

23

24 ~~Q. Please explain the adjustment shown in Column A of Page 3A,~~
25 ~~Schedule 1?~~

~~1 additional 20% of the project from the rate base. When this amount
2 is removed from rate base, it becomes necessary to remove from the
3 income statement the AFUDC that was accrued during 1982 on this
4 20% of the project. Schedule No. 7 shows the details of this
5 calculation.~~

6
7 Q. Mr. Johnson, please explain the adjustment shown in Column H on
8 Page 3B and detailed on Schedule 8 which relates to the cancellation
9 of North Anna Unit 3.

10 A. On November 19, 1982, the Board of Directors of the Company
11 approved management's recommendation to cancel North Anna Unit
12 3. The primary reasons for the cancellation of this unit were the
13 large increase in estimated costs currently projected to complete the
14 project, and the expected availability to the Company of equivalent
15 generating capacity at lower costs from neighboring utilities.
16 Mr. William W. Berry and Mr. Jack H. Ferguson have discussed the
17 reasons for and expected benefits from the cancellation of this unit.

18 The adjustment shown in my exhibit amortizes the costs
19 incurred with respect to that unit over a 10-year period on a
20 levelized basis and includes the unamortized balance in rate base. As
21 of December 31, 1982, the Company had \$570.5 million invested in
22 North Anna Unit 3 and after the transfer of certain parts and
23 equipment (\$114.8 million) to other units, the total investment is
24 reduced to \$456.0 million. Contractual obligations and cancellation
25 costs are projected to be an additional \$25.7 million, bringing the

1 total cost of cancellation to \$481.7 million, as detailed on Page 2 of
2 Schedule 8.

3 The Company will account for the loss incurred as a result of
4 the cancellation of North Anna Unit 3 as provided in FERC Account
5 182 - Extraordinary Property Losses. The accounting treatment that
6 we propose to follow has been approved by the Commission Staff and
7 is basically the same procedure that was approved with respect to the
8 cancellation of Surry Units 3 and 4 in the Commission's Order dated
9 March 19, 1979 in Case No. 19960 and the cancellation of North Anna
10 Unit 4 in the Commission's Order dated August 24, 1981 in Case No.
11 PUE810025. The amounts previously recorded in FERC Account 107
12 - Construction Work in Progress, net of transfers, were transferred
13 to FERC Account 182. Pursuant to instructions for FERC Account
14 407 - Amortization of Property Losses, the balance in FERC Account
15 182 would be amortized through charges to FERC Account 407.

16 Abandonment losses are deductible for Federal income tax
17 purposes in the year the decision to abandon is made. Accordingly,
18 expenditures to date, plus additional cancellation expenditures, less
19 allowance for funds used during construction, taxes and benefit plans
20 capitalized per books but deducted in prior years for Federal income
21 tax purposes, and any salvage (including sales and transfers to
22 inventory and/or other units) should be allowable deductions for
23 Federal income tax purposes in the year 1982. In addition, the
24 impact on certain Federal income tax accruals resulting from the
25 cancellation of North Anna 3 were also deferred in 1982 and are

1 included in the revenue requirement necessary because of such
2 cancellation and will be amortized concurrently with the reduction in
3 Federal income taxes discussed above.

4 Pursuant to the approval granted by the Commission Staff, the
5 Company deferred the reduction in Federal income taxes resulting
6 from the cancellation through credit to Account 283-Accumulated
7 Deferred Income Taxes, Other and debit to Account 410.1, Provision
8 for Deferred Income Taxes-Utility Operating Income and will
9 amortize such tax reduction over the same amortization period as
10 approved for the related amounts charged to Account 182, thus
11 matching the tax effect with the expense charged to income.

12 Deferred taxes provided in prior years with respect to taxes and
13 benefit plans capitalized per books but deducted for Federal income
14 tax purposes will also be amortized over the same amortization
15 period through a credit to Account 411.1, Provision for Deferred
16 Income Taxes-Credit, Utility Operating Income and a debit to
17 Account 283, Accumulated Deferred Income Taxes-Other.

18 We propose a 10-year amortization period, on a levelized basis,
19 beginning with approval of the rate-making treatment covering the
20 cancellation costs. Under the levelized approach, which is similar to
21 the typical fixed-term home mortgage, recovery of the investment is
22 a smaller portion of the write-off in the early years when the return
23 on the unamortized balance is at its highest level. As this return
24 requirement decreases, the recovery of the investment increases
25 resulting in a constant amount of recovery for each year.

1 The annual levelized amount is achieved by computing the equal
2 payments necessary to amortize the total amount to be written-off
3 over the 10-year period and provide a return on the unamortized
4 balance of 6.83%, which has been adjusted for the effect of interest
5 synchronization on Federal income taxes. We have used an 8.82%
6 rate of return, which is the projected 1983 overall rate of return
7 using the 1982 earned return on equity of 10.1%. We have limited the
8 return on equity applicable to North Anna Unit 3 to the realized 1982
9 return on equity of 10.1% rather than the 16% requested in this case
10 to minimize the impact on our customers, and to recognize the fact
11 that future equity investment will not be required as is the case for
12 continuing construction programs. Page 3 of Schedule 8, Exhibit
13 VEPCO-BDJ ____, Part 1 shows the annual levelized amount
14 segregated between the net of tax write-off each year and the return
15 on the declining unamortized balance. As shown, the levelized annual
16 revenue requirement is \$64.9 million. Under the straight line
17 method, this revenue requirement would be \$77.3 million. However,
18 you should recognize that the rate base at December 31, 1982,
19 excludes the amount of North Anna Unit 3 (a negative revenue
20 requirement of \$64.7 million) and that we have eliminated the test
21 year's AFUDC attributable to North Anna Unit 3 CWIP (a positive
22 revenue requirement of \$26.7 million). Accordingly, the revenue
23 requirement attributable to these calculations reduces the North
24 Anna Unit 3 revenue requirement by \$38.0 million. Subtracting this
25 from the levelized annual revenue requirement of \$64.9 million

1 produces a net revenue requirement associated with the cancellation
2 of North Anna Unit 3 of \$26.9 million.

3

4 Q. How does this revenue requirement associated with the cancellation
5 of North Anna Unit 3 compare with what would have been required if
6 the Company had decided to continue construction of North Anna
7 Unit 3?

8 A. This is shown on Page 4 of Schedule 8, of Part 1 of my Exhibit. If the
9 Company had decided to continue the construction of North Anna
10 Unit 3, the revenue requirement would have been \$61.3 million in this
11 first year.

12 This should be considered as an offset to the revenue
13 requirement attributable to cancellation, so the true cost to
14 customers of the cancellation in the first year is only \$3.6 million.

15 In future years, when larger construction expenditures would
16 have been incurred, the revenue requirement attributable to the
17 cancellation will be less than the revenue requirement for continued
18 construction.

19 These calculations do not take into account the higher cost of
20 the additional financing that would be required if the unit were
21 constructed. The revenue requirement for continued construction is
22 undoubtedly understated, since this additional financing would raise
23 the cost of capital above 10.87%

24

25 Q. Please discuss the Company's evaluation of the impact of the decision

1 to cancel North Anna Unit 3 on its customers and stockholders.

2 A. Our evaluation compared two scenarios: (1) build North Anna Unit 3
3 assuming the dramatically higher costs of completing the Unit; and
4 (2) cancel North Anna Unit 3, assuming that there would be
5 economical capacity available from neighboring utilities to replace
6 the lost capacity.

7 In the case of building North Anna Unit 3, we assumed for
8 purposes of our analysis that the Unit would cost approximately in
9 the range of \$3.8 billion to \$4.6 billion based upon a 1990 commercial
10 operation date. This cost depended on the assumed regulatory
11 treatment for Allowance for Funds Used During Construction and
12 Construction Work in Progress.

13 In the case of cancelling North Anna Unit 3, we assumed that
14 total cancellation costs would amount to approximately \$580 million
15 before Federal income tax effect. That cost has now been
16 significantly reduced to about \$482 million. For the purpose of our
17 evaluation, we assumed a ten-year amortization period for the write-
18 off and a full return on the unamortized balance in rate base. We
19 also assumed a capacity purchase of 900 megawatts of coal fired
20 generation for the period 1986 through 1995. This purchase
21 assumption included a \$15.9 kilowatt per month capacity charge, or
22 approximately \$172 million per year in capacity charges. The energy
23 cost was assumed to be based upon future expected coal prices or 31
24 mills per kilowatt beginning in 1986. After the termination of the
25 assumed capacity purchase, we added a 550 MW coal fired plant in

1 1996 to our expansion plan in order to maintain acceptable future
2 reserve margins.

3

4 Q. Mr. Johnson, how were these scenarios evaluated?

5 A. Because of the long-term impact of the North Anna Unit 3
6 cancellation decision, we evaluated the build versus cancel scenarios
7 using the Company's long range financial models. These models are
8 strategic in nature and have the capability to project financial data
9 thirty years into the future. A number of financial criteria were
10 evaluated, including system average revenue per kilowatt-hour, fuel
11 costs, construction expenditures, financing requirements,
12 capitalization ratios and coverage ratios. The model-assisted
13 evaluation allowed us to compare the two alternatives (build versus
14 cancel) and evaluate the relative trade-offs of the alternative
15 scenarios on our customers and stockholders.

16

17 Q. What were the results of the Company's evaluation?

18 A. Simply stated, neither our customers nor our stockholders could
19 benefit from the completion of the construction of North Anna Unit
20 3. The greatly increased costs of completing the Unit would result in
21 significantly higher external financing requirements, higher costs of
22 capital, and higher rates to our customers. With the opportunity to
23 replace North Anna Unit 3 with economical capacity, our
24 stockholders and customers would be better off if the Unit were
25 cancelled, written off over ten years, and the unamortized balance of

1 the property loss included in rate base.

2

3 Q. Mr. Johnson, why should the unamortized North Anna Unit 3 property
4 loss be included in rate base?

5 A. The dollars invested in North Anna Unit 3 were, at the time the
6 investment was made, prudently invested for the purpose of
7 furnishing public utility service to our customers. The customers
8 should, therefore, pay the costs of that investment. This is especially
9 true where, as here, the cancellation will produce lower rates for
10 customers.

11 The decision to cancel North Anna Unit 3 will produce
12 substantial savings to our customers even with a return on the
13 unamortized property loss. The basis for cancellation is different
14 from previous cancellations reviewed by the Commission in that the
15 Unit was cancelled because of excessive costs and with the
16 confidence that more economical means were available to replace
17 that cancelled capacity. From our customers' perspective it is in
18 their best interest for North Anna Unit 3 to be cancelled and to be
19 replaced with more economical capacity.

20 Exclusion of the property loss from rate base would unfairly
21 penalize the stockholders as a result of a decision which will benefit
22 the customers. Thus the cancellation was an economic decision for
23 the benefit of the customer and justifies the rate base inclusion.

24

25 Q. Mr. Johnson, please describe the Federal income tax adjustment

1 associated with the interest synchronization shown in Column I of
2 Part 1 Schedule 1, Page 3B.

3 A. This adjustment, which is detailed in Schedule 9, shows the increase
4 in Federal income taxes which would result from using annualized
5 interest rather than actual interest expenses as a tax deduction so as
6 to synchronize such deduction with the debt component included in
7 the cost of capital. The 1983 rate of return component for total debt
8 decreased causing annualized interest expense to be lower than the
9 actual interest expenses for 1982. The interest synchronization
10 adjustment has been required by the Commission for several years.

11
12 Q. Mr. Johnson, does this complete the explanation of your adjustments?

13 A. Yes, it does.

14
15 Q. What is the adjusted rate of return after adjustments from Virginia
16 jurisdictional operations for the 12 months ended December 31, 1982,
17 before giving effect to the rate increase requested?

18 A. As shown on Exhibit VEPCO-BDJ ____, Part 1, Schedule 1, Page 1,
19 Column F, Line 50, the adjusted rate of return, after general rate
20 case adjustments and before giving effect to the rate increase
21 requested, is 8.61%.

22
23 Q. Mr. Johnson, Line 1, Column G, shows an amount of additional
24 revenue requirement of \$175,213,000. What is the basis for this
25 requirement?

1 A. \$175,213,000 is the amount of additional revenue that would be
2 necessary, to produce, on a pro forma basis, a 10.87% rate of return.

3

4 Q. How was the 10.87% rate of return determined?

5 A. The 10.87% rate of return was supplied to me by Mr. Peterson, who
6 computed the cost of capital using a 16.0% cost of common equity.
7 He discusses the determination of such cost of capital in his
8 testimony.

9

10 Q. Mr. Johnson, do you have a statement showing the rate of return
11 from the Company's Virginia Jurisdictional operations for the twelve
12 months ended December 31, 1982, based on the Commission's
13 proposed "Revised Rules Governing Financial Operating Review and
14 Utility Rate Case Filings" as it relates to expedited rate filings?

15 A. Yes. Exhibit VEPCO-BDJ ____, Part 2, Schedule 1, presents that
16 information. Schedule 1, Page 1, shows, for the test period, net
17 operating income, rate base and rate of return in Columns A - D
18 identical to the format used in Exhibit VEPCO-BDJ ____, Part 1.
19 Schedule 1 shows the appropriate adjustments, the calculation of
20 rates of return, and a calculation of the additional revenue
21 requirement based on the expedited rules.

22

23 Q. What is the purpose of this exhibit, Mr. Johnson?

24 A. The purpose of this exhibit is to demonstrate the level of additional
25 annual revenue that would be appropriate under the Commission's

QUALIFICATIONS OF B. D. JOHNSON

Mr. B. D. Johnson graduated from Phillips Business College and has completed numerous courses of study in accounting, finance, taxation and management at the University of Richmond and the Georgia Institute of Technology. While serving with the United States Air Force during 1952 - 1956, Mr. Johnson held several supervisory positions with the Comptroller Division in the fields of finance and cost accounting.

Upon returning from service in 1956, Mr. Johnson was employed by Vepco in the Accounting Department. He became Tax Accountant in 1958 and was promoted to Supervisor of Taxes in 1962, to Assistant Treasurer in 1965, to Executive Manager - Accounting and Control on October 1, 1975, to Executive Manager - Accounting and Control and Comptroller on August 19, 1977, and to his present position of Vice President and Controller on January 1, 1978.

Mr. Johnson has attended several executive management courses and is a member of the Edison Electric Institute Accounting Executive Committee and is the past Chairman of the Southeastern Electric Exchange Accounting and Finance Division Executive Committee.

Mr. Johnson has previously testified in general rate proceedings before this Commission and before the North Carolina Utilities Commission and the Public Service Commission of West Virginia.

VIRGINIA ELECTRIC AND POWER COMPANY
RATE OF RETURN STATEMENT
YEAR ENDED DECEMBER 31 1982
(Thousands of Dollars)

	Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H
	System Electric				Virginia Jurisdictional Service			

	Per Books	Tax Adjustments (Page 2)	As Adjusted	Allocated to Virginia Jurisdiction	General Rate Case Adjustments Page 3 Column J	Pro Forma Amounts After Adjustments	Revenue Requirement for 10.87% Rate of Return	Pro Forma Amounts Additional Revenue Requirement
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Line No.	Description	Per Books	Tax Adjustments (Page 2)	As Adjusted	Allocated to Virginia Jurisdiction	General Rate Case Adjustments Page 3 Column J	Pro Forma Amounts After Adjustments	Revenue Requirement for 10.87% Rate of Return	Pro Forma Amounts Additional Revenue Requirement
NET OPERATING INCOME									
1	Operating Revenues	2,254,526		2,254,526	1,690,551	32,639	1,723,190	175,213	1,898,403
Operating Expenses and Taxes:									
2	Operation and Maintenance Expenses	1,259,687		1,259,687	917,901	22,533	940,434	368	940,802
3	Depreciation	188,625		188,625	135,966	6,225	142,191		142,191
4	Amortization of Property Losses	21,221		21,221	16,261	25,028	41,289		41,289
5	Gain or Loss on Disposition of Property	(52)		(52)	(38)		(38)		(38)
Federal Income Taxes:									
6	Net Current	(8,392)	6,730	(1,662)	8,542	23,198	31,740	64,679	96,419
7	Investment Tax Credit	(1,399)	1,399		21,682	(4,190)	17,492	13,489	30,981
8	Investment Tax Credit - Amortization	(9,020)	1,492	(7,528)	(6,617)	114	(6,503)	(450)	(6,953)
9	Accelerated Amortization - Credit	(1,496)		(1,496)	(1,038)	(13)	(1,051)		(1,051)
10	Deferred Liberalized Depreciation	50,499	(3,341)	47,158	34,471	(1,562)	32,909		32,909
11	Deferred - Other - Virginia Gross Receipts	(1,842)		(1,842)	(1,496)	371	(1,125)		(1,125)
12	- Fuel Adjustment	11,030	(17,178)	(6,148)	(9,953)	403	(9,550)		(9,550)
13	- Benefit Plans Capitalzld	1,815	(30)	1,785	1,342	(240)	1,102		1,102
14	- Taxes Capitalized	1,932	427	2,359	1,743	(244)	1,499		1,499
15	- Cost of Removal	6,509	(1,453)	5,056	3,886	19	3,905		3,905
16	- Abandoned Project Costs	125,328	263	125,591	88,601	(8,181)	80,420		80,420
17	- Permanent Disposal Costs	(3,049)		(3,049)					
18	- Reprocessing Costs	(10,960)	3,367	(7,593)	(6,813)		(6,813)		(6,813)
19	- Decommissioning Costs	(743)		(743)	(378)		(378)		(378)
20	- Preliminary Operations	(5,280)	5,616	336	249		249		249
21	- Spare Parts Inventory	(1,004)		(1,004)	(751)	525	(226)		(226)
22	- Gain on Sale/Leaseback	83		83	68		68		68
23	- Nuclear Fuel - Owned	(4,946)	2,848	(2,098)	(1,485)	(2)	(1,487)		(1,487)
24	- Variable Prime Interest	1,855	73	1,928	1,403	13	1,416		1,416
25	- Customer Accts. Reserve	242	(1)	241					
26	- FERC - Full Normalization	1,029		1,029					
27	Other Taxes	130,521	2	130,523	93,192	2,803	95,995	4,915	100,910
28	Total Operating Expenses and Taxes	1,752,193	214	1,752,407	1,296,738	66,800	1,363,538	83,001	1,446,539
29	Net Operating Revenues	502,333	(214)	502,119	393,813	(34,161)	359,652	92,212	451,864
30	Add: AFUDC Including Nuclear Fuel	83,373		83,373	57,495	(28,531)	28,964		28,964
31		585,706	(214)	585,492	451,308	(62,692)	388,616	92,212	480,828
32	Deduct: Charitable and Educational Donations Charged to Account 426 (Net after Federal Income Tax Reduction)	292		292	213	1	214		214
33	Net Operating Income	585,414	(214)	585,200	451,095	(62,693)	388,402	92,212	480,614

VIRGINIA ELECTRIC AND POWER COMPANY
RATE OF RETURN STATEMENT
YEAR ENDED DECEMBER 31 1982
(Thousands of Dollars)

Line No.	Description	Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H
		System Electric	System Electric	System Electric	Virginia Jurisdiction	Virginia Jurisdiction	Virginia Jurisdiction	Virginia Jurisdiction	Virginia Jurisdiction
		Per Books	Tax Adjustments (Page 2)	As Adjusted	Allocated to Virginia Jurisdiction	General Rate Case Adjustments Page 3 Column J	Pro Forma Amounts After Adjustments	Revenue Requirement for 10.87% Rate of Return	Pro Forma Amounts Additional Revenue Requirement
	RATE BASE - END OF PERIOD								
34	Electric Plant Including Nuclear Fuel	7,377,691		7,377,691	5,352,459	(160,717)	5,191,742		5,191,742
35	Electric Portion of Common Utility Plant	21,126		21,126	15,406	138	15,544		15,544
36	Total Plant Invested	7,398,817		7,398,817	5,367,865	(160,579)	5,207,286		5,207,286
37	Deduct: Accumulated Provision for Depreciation								
38	Electric	1,391,678		1,391,678	1,010,890	16,009	1,026,899		1,026,899
39	Electric Portion of Common Utility	4,850		4,850	3,537	(1,726)	1,811		1,811
40	Amortization of Nuclear Fuel Assemblies								
41	Front End Costs	150,431		150,431	106,478	143	106,621		106,621
42	Rear End Costs	121,066		121,066	74,925	32	74,957		74,957
43	Total Depreciation and Amortization	1,668,025		1,668,025	1,195,830	14,458	1,210,288		1,210,288
44	Plant Investment Less Provision for Depreciation	5,730,792		5,730,792	4,172,035	(175,037)	3,996,998		3,996,998
45	Working Capital:								
46	Materials and Supplies (13-month Average)	210,917		210,917	150,965	(3,151)	147,814		147,814
47	Cash(20 Days In-system Fossil Fuel; 40 Days Other)	111,854		111,854	79,383	2,481	81,864		81,864
48	Deferred Fuel Expense Less Federal Income Tax Deferred	50,379		50,379	46,168	(7,170)	38,998		38,998
49	Prepaid Virginia Gross Receipts Taxes Less Federal Income Tax Deferral	13,073		13,073	10,621	(6,035)	4,586		4,586
50	Total Working Capital	386,223		386,223	287,137	(13,875)	273,262		273,262
51	Unamortized Abandoned Project Costs less Federal Income Tax Deferral					240,661	240,661		240,661
52	Total Rate Base - End of Period	6,117,015		6,117,015	4,459,172	51,749	4,510,921		4,510,921
53	50 RATE OF RETURN	9.57		9.57	10.12		8.61		10.87

45

VIRGINIA ELECTRIC AND POWER COMPANY
SYSTEM ELECTRIC
EXPLANATION OF ADJUSTMENTS REQUIRED FOR RATE OF RETURN PURPOSES
TWELVE MONTHS ENDED DECEMBER 31, 1982

(Thousands of Dollars)

Adj. Number	Description	Amount	
		Prior Period Items	Estimated Revised To Actual
	<u>Federal Income Taxes</u>		
	Net Current:		
(1)	Federal Income Tax Return - 1981	\$ 2,627	\$ 2,627
(2)	Tax Depreciation		\$ (930)
(3)	Cost of Removal		(564)
(4)	North Carolina State Income Tax Return	(9)	(9)
(5)	Taxes - Other	(33)	13
(6)	North Carolina State Income Tax	9	4
(7)	West Virginia State Income Taxes	6	6
(8)	Benefit Plans Capitalized		31
(9)	ESOP Administrative Expenses	(28)	(28)
(10)	Elimination - Non-Operating Income		410
(11)	IRS Adjustment	6,510	6,510
	Current Tax Before Reduction for Investment Tax Credit	\$ 9,082	\$ (1,036)
	Reduction Due to Investment Tax Credit		
	- Non-Operating Income Elimination		\$ 15,200
	- Investment Tax Credit Differential		2
	- 1981 Tax Return Adjustment	(14,986)	(14,986)
	- North Anna #4 Property Loss	157	157
	- Operating Income Investment Tax Credit		(8,337)
	- 1968-1975 IRS Adjustment	6,648	6,648
		(8,181)	(1,315)
	Net Current:		6,730
(12)	Investment Tax Credit - Gross		1,399
(13)	Investment Tax Credit - Amortization		1,492
	<u>Deferred</u>		
(14)	Fuel Adjustment	(17,178)	(17,178)
(15)	Liberalized Depreciation	(3,344)	(3,341)
(16)	Benefit Plans Capitalized		(30)
(17)	Taxes	427	427
(18)	Cost of Removal	(2,017)	564
(19)	Abandoned Project Costs	(2)	265
(20)	Preliminary Operations	5,616	5,616
(21)	Reprocessing Costs - Nuclear Fuel	3,367	3,367
(22)	Nuclear Fuel Owned	2,848	2,848
(23)	Variable Prime Interest	73	73
(24)	Customer Accounts Reserve	(1)	(1)
	<u>Taxes - Other</u>		
(25)	North Carolina State Income Tax	(19)	(9)
(26)	Business & Occupation Tax	(273)	44
(27)	Virginia Local and Valuation Tax on Fuel Clause Revenues	345	(71)
(28)	Taxes - Other Non-Operating	(1)	(1)
(29)	West Virginia State Income Tax	(14)	(14)
	Total Taxes - Other	\$ 38	\$ (36)
	Total Adjustments		\$ 214

VIRGINIA ELECTRIC AND POWER COMPANY
SUMMARY OF GENERAL RATE CASE ADJUSTMENTS
YEAR ENDED DECEMBER 31 1982
(Thousands of Dollars)

Line No.	Description	Column A Annualized Base Rates Effective 8/30/82 (Schedule 2)	Column B Load Loss Adjustment (Schedule 3)	Column C General Rate Case Miscellaneous Adjustments (Schedule 4)	Column D Effect of Gradual Elimination of AFUDC (Schedule 5)	Column E Eliminate AFUDC re: North Anna 3 & Bath Co. (Schedule 6)	Column F Eliminate Additional 20% Bath Co. Project (Schedule 7)	Column G Total Schedules 2 - 7 to Page 3 Continued
NET OPERATING INCOME								
1	Operating Revenues	32,633	6					32,639
Operating Expenses and Taxes:								
2	Operation and Maintenance Expenses	69	2,720	19,744				22,533
3	Depreciation		1,183	5,042				6,225
4	Amortization of Property Losses		209	(298)				(89)
5	Gain or Loss on Disposition of Property							
Federal Income Taxes:								
6	Net Current	14,559	(384)	(10,531)				3,644
7	Investment Tax Credit		(4,190)					(4,190)
8	Investment Tax Credit - Amortization		114					114
9	Accelerated Amortization - Credit		(13)					(13)
10	Deferred Liberalized Depreciation		375	(1,937)				(1,562)
11	Deferred - Other - Virginia Gross Receipts			371				371
12	- Fuel Adjustment			403				403
13	- Benefit Plans Capitalized		3	(243)				(240)
14	- Taxes Capitalized		9	(253)				(244)
15	- Cost of Removal		19					19
16	- Abandoned Project Costs		1,172	(1,795)				(623)
17	- Permanent Disposal Costs							
18	- Reprocessing Costs							
19	- Decommissioning Costs							
20	- Preliminary Operations							
21	- Spare Parts Inventory		(3)	528				525
22	- Gain on Sale/Leaseback							
23	- Nuclear Fuel Owned		(2)					(2)
24	- Variable Prime Interest		13					13
25	- Customer Accts. Reserve							
26	- FERC - Full Normalization							
27	Other Taxes	915	290	1,598				2,803
28	Total Operating Expenses and Taxes	15,543	1,515	12,629				29,687
29	Net Operating Revenues	17,090	(1,509)	(12,629)				2,952
30	Add: AFUDC Including Nuclear Fuel		790		(4,901)	(16,597)	(7,823)	(28,531)
31		17,090	(719)	(12,629)	(4,901)	(16,597)	(7,823)	(25,579)
32	Deduct: Charitable and Educational Donations Charged to Account 426 (Net after Federal Income Tax Reduction)		1					1
33	Net Operating Income	17,090	(720)	(12,629)	(4,901)	(16,597)	(7,823)	(25,580)

VIRGINIA ELECTRIC AND POWER COMPANY
SUMMARY OF GENERAL RATE CASE ADJUSTMENTS
YEAR ENDED DECEMBER 31 1982
(Thousands of Dollars)

Line No.	Description	Column A Annualized Base Rates Effective 8/30/82 (Schedule 2)	Column B Load Loss Adjustment (Schedule 3)	Column C General Rate Case Miscellaneous Adjustments (Schedule 4)	Column D Effect of Gradual Elimination of AFUDC (Schedule 5)	Column E Eliminate AFUDC re: North Anna 3 & Bath Co. (Schedule 6)	Column F Eliminate Additional 20% Bath Co. Project (Schedule 7)	Column G Total Schedules 2 - 7 to Page 3 Continued
	RATE BASE - END OF PERIOD							
34	Electric Plant Including Nuclear Fuel		46,191	(66,486)		(140,422)	(160,717)	
35	Electric Portion of Common Utility Plant		138				138	
36	Total Plant Investment		46,329	(66,486)		(140,422)	(160,579)	
	Deduct: Accumulated Provision for Depreciation							
37	Electric		7,760	8,249			16,009	
38	Electric Portion of Common Utility Amortization of Nuclear Fuel Assemblies		32	(1,758)			(1,726)	
39	Front End Costs		143				143	
40	Rear End Costs		32				32	
41	Total Depreciation and Amortization		7,967	6,491			14,458	
42	Plant Investment Less Provision for Depreciation		38,362	(72,977)		(140,422)	(175,037)	
	Working Capital:							
43	Materials and Supplies(13-month Average)		865	(4,016)			(3,151)	
44	Cash(20 Days In-system Fossil Fuel; 40 Days Other)	8	279	2,194			2,481	
45	Deferred Fuel Expense Less Federal Income Tax Deferred			(7,170)			(7,170)	
46	Prepaid Virginia Gross Receipts Taxes Less Federal Income Tax Deferral			(6,035)			(6,035)	
47	Total Working Capital	8	1,144	(15,027)			(13,875)	
48	Unamortized Abandoned Project Costs less Federal Income Tax Deferral							
49	Total Rate Base - End of Period	8	39,506	(88,004)		(140,422)	(188,912)	

VIRGINIA ELECTRIC AND POWER COMPANY
SUMMARY OF GENERAL RATE CASE ADJUSTMENTS
YEAR ENDED DECEMBER 31 1982
(Thousands of Dollars)

Line No.	Description	Column G Total Schedules 2 - 7 to Page 3 Continued	Column H North Anna 3 Cancellation (Schedule 8)	Column I Interest Synchronization on Federal Income Taxes (Schedule 9)	Column J Total Schedules 2 - 9 to Page 1 Column E
NET OPERATING INCOME					
1	Operating Revenues	32,639			32,639
	Operating Expenses and Taxes:				
2	Operation and Maintenance Expenses	22,533			22,533
3	Depreciation	6,225			6,225
4	Amortization of Property Losses	(89)	25,117		25,028
5	Gain or Loss on Disposition of Property				
	Federal Income Taxes:				
6	Net Current	3,644		19,554	23,198
7	Investment Tax Credit	(4,190)			(4,190)
8	Investment Tax Credit - Amortization	114			114
9	Accelerated Amortization - Credit	(13)			(13)
10	Deferred Liberalized Depreciation	(1,562)			(1,562)
11	Deferred - Other - Virginia Gross Receipts	371			371
12	- Fuel Adjustment	403			403
13	- Benefit Plans Capitalized	(240)			(240)
14	- Taxes Capitalized	(244)			(244)
15	- Cost of Removal	19			19
16	- Abandoned Project Costs	(623)	(7,558)		(8,181)
17	- Permanent Disposal Costs				
18	- Reprocessing Costs				
19	- Decommissioning Costs				
20	- Preliminary Operations				
21	- Spare Parts Inventory	525			525
22	- Gain on Sale/Leaseback				
23	- Nuclear Fuel Owned	(2)			(2)
24	- Variable Prime Interest	13			13
25	- Customer Accts. Reserve				
26	- FERC - Full Normalization				
27	Other Taxes	2,803			2,803
28	Total Operating Expenses and Taxes	29,687	17,559	19,554	66,800
29	Net Operating Revenues	2,952	(17,559)	(19,554)	(34,161)
30	Add: AFUDC Including Nuclear Fuel	(28,531)			(28,531)
31		(25,579)	(17,559)	(19,554)	(62,692)
32	Deduct: Charitable and Educational Donations Charged to Account 426 (Net after Federal Income Tax Reduction)	1			1
33	Net Operating Income	(25,580)	(17,559)	(19,554)	(62,693)

48

VIRGINIA ELECTRIC AND POWER COMPANY
SUMMARY OF GENERAL RATE CASE ADJUSTMENTS
YEAR ENDED DECEMBER 31 1982
(Thousands of Dollars)

Line No.	Description	Column G Total Schedules 2 - 7 to Page 3 Continued	Column H North Anna 3 Cancellation (Schedule 8)	Column I Interest Synchronization on Federal Income Taxes (Schedule 9)	Column J Total Schedules 2 - 9 to Page 1 Column E
	RATE BASE - END OF PERIOD				
34	Electric Plant Including Nuclear Fuel	(160,717)			(160,717)
35	Electric Portion of Common Utility Plant	138			138
36	Total Plant Investment	(160,579)			(160,579)
	Deduct: Accumulated Provision for Depreciation				
37	Electric	16,009			16,009
38	Electric Portion of Common Utility	(1,726)			(1,726)
	Amortization of Nuclear Fuel Assemblies				
39	Front End Costs	143			143
40	Rear End Costs	32			32
41	Total Depreciation and Amortization	14,458			14,458
42	Plant Investment Less Provision for Depreciation	(175,037)			(175,037)
	Working Capital:				
43	Materials and Supplies(13-month Average)	(3,151)			(3,151)
44	Cash(20 Days In-system Fossil Fuel; 40 Days Other)	2,481			2,481
45	Deferred Fuel Expense Less Federal Income Tax Deferred	(7,170)			(7,170)
46	Prepaid Virginia Gross Receipts Taxes Less Federal Income Tax Deferral	(6,035)			(6,035)
47	Total Working Capital	(13,875)			(13,875)
48	Unamortized Abandoned Project Costs less Federal Income Tax Deferral		240,661		240,661
49	Total Rate Base - End of Period	(188,912)	240,661		51,749

VIRGINIA ELECTRIC AND POWER COMPANY
ADJUSTMENT TO ELIMINATE AFUDC ON NORTH ANNA UNIT 3
AND PORTION OF BATH COUNTY PROJECT SOLD
YEAR ENDED DECEMBER 31 1982

(Thousands of Dollars)

Line Number	Description	System	Virginia Factor	Virginia Juris. Amount
1	20% of Bath Co. Project Sold 4/26/82:			
2	Pumped Storage Project	3,557	71.4841 (1)	2,543
	Less: Contra AFUDC	221		
3		-----		-----
		3,336		2,543
4	Bath Co. Transmission Lines	96	66.8456 (2)	64
5	Less: Contra AFUDC	8		
6		-----		-----
		88		64
7	AFUDC Elimination - Bath Co. (1/1/82 - 4/26/82)	3,424		2,607
		-----		-----
8	North Anna Unit 3 (100%):			
9	Power Station - Unit 3	21,694	71.4841 (1)	15,508
	Less: Contra AFUDC	1,859		1,518
10	AFUDC Elimination - North Anna 3	19,835		13,990
		-----		-----
11	Total AFUDC to be Eliminated	23,259		16,597
		=====		=====
12	Effect on Net Operating Income	(23,259)		(16,597)
		=====		=====

(1) Cost Allocation Study 12/31/82 w/load loss, Production Plant, Factor 1
(2) Cost Allocation Study 12/31/82 w/load loss, Transmission Plant

50

VIRGINIA ELECTRIC AND POWER COMPANY
NORTH ANNA UNIT 3 WRITE-OFF
12 MONTHS ENDED DECEMBER 31 1982

(Thousands of Dollars)

Line No.	Description	System Amount	Virginia Jurisdiction Allocation Factor %	Allocated Amounts
	To remove North Anna 3 Construction Work in Progress from the Rate Base and to amortize the loss over 10 years on a levelized basis with the unamortized balance included in the Rate Base.			
	NET OPERATING INCOME			
	Amortization of Property Loss:			
1	North Anna 3 - Plant	481,629	71.4841 (1)	344,288
2	Less: Contra AFUDC	2,095	Assigned	1,607
3		479,534		342,681
4	North Anna 3 - Nuclear Fuel: Demand (10.11%)	223	71.4841 (1)	159
5	Energy (89.89%)	1,984	70.8088 (2)	1,405
6	Total	481,741		344,245
7	Adjustment (First Year Write Off)	35,148		25,117
	Fed Income Taxes Deferred-Abandoned Project Costs			
8	North Anna 3 - Plant	(143,898)	71.4841 (1)	(102,864)
9	North Anna 3 - Nuclear Fuel: Demand (10.11%)	(103)	71.4841 (1)	(74)
10	Energy (89.89%)	(912)	70.8088 (2)	(646)
11	Total	(144,913)		(103,584)
12	Adjustment (First Year Write Off)	(10,573)		(7,558)
13	Total Operating Expenses and Taxes	24,575		17,559
14	Effect on Net Operating Income	(24,575)		(17,559)
	RATE BASE			
	Unamortized Abandoned Project Cost less Federal Income Tax Deferral:			
15	North Anna 3 - Plant	337,731	71.4841 (1)	241,424
16	Less: Contra AFUDC	2,095	Assigned	1,607
17		335,636		239,817
18	North Anna 3 - Nuclear Fuel: Demand (10.11%)	120	71.4841 (1)	85
19	Energy (89.89%)	1,072	70.8088 (2)	759
20	Total	336,828		240,661
21	Effect on Rate Base	336,828		240,661

51

VIRGINIA ELECTRIC AND POWER COMPANY
NORTH ANNA UNIT 3 ESTIMATED WRITE-OFF
AS OF DECEMBER 31, 1982

Construction Charges:	
Actual at 12/31/82	\$570,459,481
Cancellation Charges:	
Stone and Webster	820,000
Babcock and Wilcox	8,200,000
Other	3,103,000
Demobilization, Administrative, Misc.	10,000,000
Restoration	4,000,000
Salvage and Disposal:	
Equipment and Material	(47,358,374)
AFUDC	(21,154,497)
Buildings and Facilities	(11,116,417)
AFUDC	(4,965,583)
Vehicles and Power Oper. Equip. transferred to PIP	(284,890)
AFUDC	(127,205)
Land Parcel to North Anna Building and Facilities	(1,189)
AFUDC	(531)
North Anna 3 Generator	(10,029,283)
AFUDC	(4,478,395)
North Anna 4 Generator	(10,027,771)
AFUDC	(4,477,720)
Misc. Equip. and Charges Transf. from Extra Property	(419,903)
Scrap Sales	(400,000)
TOTAL ESTIMATED WRITE-OFF	<u>\$481,740,723</u>

VIRGINIA ELECTRIC AND POWER COMPANY
NORTH ANNA UNIT 3 CANCELLATION
ABANDONED PROJECT COSTS
AS OF DECEMBER 31, 1982

	<u>System</u> <u>(000)</u>	<u>Allocated to Virginia</u> <u>Factor</u>	<u>Amount</u>
Plant And AFUDC	\$481,629	71.4841%(1)	\$344,288
Contra-AFUDC	(2,095)	Assigned	(1,607)
	<u>479,534</u>		<u>342,681</u>
Less: Deferred FIT - Property Loss	143,898	71.4841%(1)	102,864
	<u>335,636</u>		<u>239,817</u>
Fuel - Demand	223	71.4841%(1)	159
- Energy	1,984	70.8088%(2)	1,405
Less: Deferred FIT - Property Loss			
Demand	103	71.4841%(1)	74
Energy	912	70.8088%(2)	646
	<u>1,192</u>		<u>844</u>
 TOTAL WRITE-OFF	 <u>\$336,828</u>		 <u>\$240,661</u>

Return on Equity Adjusted for Tax
Effect of Interest Synchronization

ROE	10.10%
ROR	8.82%
Interest Synch. Adjustment	1.99%(a)
	<u>6.83%</u>

<u>Year</u>	<u>Write-Off</u> <u>(Net of Tax)</u>	<u>Return On</u> <u>Unamortized</u> <u>Balance</u>	<u>Levelized</u> <u>Annual Amt.</u>	<u>Revenue</u> <u>Requirement(b)</u>
1	\$ 17,559	\$16,437	\$ 33,996	\$ 64,913
2	18,758	15,238	33,996	64,913
3	20,039	13,957	33,996	64,913
4	21,408	12,588	33,996	64,913
5	22,870	11,126	33,996	64,913
6	24,432	9,564	33,996	64,913
7	26,101	7,895	33,996	64,913
8	27,884	6,112	33,996	64,913
9	29,788	4,208	33,996	64,913
10	<u>31,822</u>	<u>2,173</u>	<u>33,995</u>	<u>64,911</u>
 TOTALS	 <u>\$240,661</u>	 <u>\$99,298</u>	 <u>\$339,959</u>	 <u>\$649,128</u>

(a) $(4.33 \times .46) = 1.99$
Total Debt Component 4.33%
Federal Income Tax Rate 46.00%

(b) Gross-up factor = 52.3718%

(1) Cost Allocation Study, 12/31/82, Factor 1.
(2) Cost Allocation Study, 12/31/82, Factor 3.

VIRGINIA ELECTRIC AND POWER COMPANY
COMPARISON OF REVENUE REQUIREMENT
IN FIRST YEAR AFTER CANCELLATION
FOR NORTH ANNA UNIT 3 CANCELLATION AND
NORTH ANNA UNIT 3 IF CONSTRUCTION HAD CONTINUED

(Millions of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>Revenue Requirement</u>	
		<u>Column A</u>	<u>Column B</u>
	<u>North Anna Unit 3 Cancelled</u>		
1	10 year write-off	\$ 33.5	
2	Return on Unamortized balance	40.5	
3	Interest synchronization for Federal Income Tax purposes	<u>(9.1)</u>	
4	Total Revenue Requirement		64.9
	<u>North Anna Unit 3 if Construction Had Continued</u>		
5	Return on rate base	\$ 82.2	
6	AFUDC in income in test period	(38.2)	
7	Interest synchronization for Federal Income Tax purposes	(15.5)	
8	Elimination of AFUDC on expenditures after August 31, 1981 for the period September 1, 1983 to August 31, 1984	<u>32.8</u>	
9	Total Revenue Requirement		<u>61.3</u>
10	Revenue Requirement for cancellation exceeds revenue requirement if construction had continued (First year after cancellation)		<u>\$ 3.6</u>

TESTIMONY OF O. JAMES PETERSON, III
FOR
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE
THE STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. 70E 930029

55

1 Q. Please state your name, position and responsibilities of that position.

2 A. My name is O. James Peterson, III and I am Vice President and
3 Treasurer for Virginia Electric and Power Company. A statement of
4 my background, qualifications and responsibility is presented in detail
5 in Appendix I to this testimony.

6

7 Q. Mr. Peterson, will you present an exhibit with your testimony?

8 A. Yes, Vepco-OJP ____ was prepared under my supervision and
9 direction and is correct to the best of my knowledge and belief.

10

11 Q. Mr. Peterson, what is the purpose of your testimony in this
12 proceeding?

13 A. My testimony will cover the Company's capital structure and cost of
14 capital at December 31, 1982 and projected capital structure and
15 cost of capital at December 31, 1983. I will also discuss the
16 embedded cost of debt and preferred stock, the returns actually
17 earned on common equity, the market price and book value of
18 common stock and the interest and fixed charge coverage
19 calculations on the Company's debt and preferred stock. I will
20 discuss the Company's efforts in meeting the challenge of raising
21 capital in today's money markets, the effects of inflation, interest
22 rates and regulatory action.

23

24 Q. Mr. Peterson, please discuss your Schedule 1 and tell us what was the
25 Company's cost of capital at the end of the test year, December 31,

1 1982.

2 A. The cost of capital is calculated and shown on Schedule 1 of my
3 exhibit. Columns A and B of Schedule 1 show the amount of capital
4 investment outstanding at the end of the test year, December 31,
5 1982 and the percent of each to the total. Funds produced by the
6 Company's Customer Stock Purchase Plan, which began in 1980 and
7 allows our customers to purchase common stock on an installment
8 basis, are shown on Line 14. Column C shows the annualized cost of
9 debt and preferred and preference stock. Column D shows, in
10 percentages, the embedded cost of debt and preferred and preference
11 stock. Column D also shows the return on common equity of 15% as
12 allowed in our Financial Operating Review (F.O.R.) proceeding last
13 year, Case No. PUE820018. The 10.54% rate of return from this
14 statement is used by Mr. Johnson in Part 2 of his exhibit to measure
15 the revenue requirement requested under the proposed guidelines for
16 utilities seeking an expedited increase in rates.

17

18 Q. Mr. Peterson, your Schedule 1 shows \$90 million of short-term debt
19 (net of short-term investments) weighted average over 1982 at a cost
20 of 11.86%. Is it unusual for the Company to have such a large
21 amount of short-term debt outstanding?

22 A. No, it is not unusual. On the contrary, we frequently have large
23 amounts of short-term debt outstanding. For example, the monthly
24 average outstanding balance of short-term debt for the ten-year
25 period 1972-1981 was in excess of \$100 million and during that period

1 the Company's average total capitalization was significantly smaller
2 than it is today. Short-term debt is a permanent and essential part of
3 our capital structure on which we rely to meet capital requirements
4 in advance of permanent or long term financings. The timing of such
5 long term financings is planned to take advantage of favorable
6 market conditions, thereby minimizing the cost of issuing stocks and
7 bonds. We could not sell securities on the most favorable terms if we
8 were simply to issue securities whenever money for capital
9 expenditures was required. It is clearly in the best interest of our
10 customers that we manage our financing in this way and, therefore,
11 the amount and cost of short-term debt should be included in the
12 calculation of our overall cost of capital.

13

14 Q. How does the Company raise money in the short-term money market?

15 A. Short-term financing is carried out through the sale of commercial
16 paper, borrowing pursuant to a master note and tax-exempt pollution
17 control commercial paper. We also borrow under short term bank
18 lines of credit from time to time. The Company is the only electric
19 utility in the country that is itself a direct issuer of its commercial
20 paper. We sell our paper directly to institutional investors in the
21 southeastern United States and have had as much as \$113 million of
22 directly placed short-term debt outstanding at one time. By selling
23 commercial paper directly, instead of through a broker, the Company
24 has achieved substantial savings on short-term financing costs.

25

1 Q. Mr. Peterson, what is the projected cost of capital for the future test
2 period at December 31, 1983?

3 A. Schedule 2, presented in the same format as Schedule 1, shows the
4 cost of capital with the return on common equity of 16% requested in
5 this case, which is within the range that Mr. J. P. Carney and
6 Mr. Eugene Meyer, the Company's cost of capital witnesses, find is
7 necessary for the Company to attract capital. We have used this rate
8 on Lines 15 and 16 in determining the cost of capital. The projected
9 cost of capital is estimated to be 10.87% at December 31, 1983, this
10 is the rate of return used by Mr. Johnson to determine the Company's
11 Virginia jurisdictional revenue requirement requested to be effective
12 August 29, 1983.

13

14 Q. Mr. Peterson, turning now to the equity portion of the Company's
15 capital structure, has the Company been able to earn its cost of
16 equity in recent years?

17 A. No. Indeed Schedule 3 shows that through most of the 1970's as the
18 cost of senior capital has increased, the Company's return on equity
19 has declined. In the 1980's there has been some improvement in the
20 Company's earned return on common equity, but not nearly enough.
21 At December 31, 1982 the return on equity was 10.12%, not quite
22 back to the 10.26% rate of return earned eleven years ago at
23 December 31, 1971. The current return is still well below the return
24 on common equity allowed by this Commission, so the need for
25 continued improvement is evident.

1 Also on Schedule 3, the embedded cost of mortgage bonds,
2 shown on Line 1, has risen sharply from 5.99% at December 31, 1971
3 to 8.95% at December 31, 1982. Similarly, the embedded cost on
4 total long-term debt, on Line 7, has risen from 5.86% at December
5 31, 1971 to 9.04% at December 31, 1982.

6 Line 8 shows that the embedded cost of preferred and prefe-
7 rence stock increased from 6.40% at December 31, 1971 to 8.51% at
8 December 31, 1982. Line 9 shows the increase in embedded cost of
9 total Senior Capital from 5.94% at December 31, 1971 to 9.01% on
10 December 31, 1982.

11

12 Q. Mr. Peterson, have the lower levels of return on common equity
13 shown on your Schedule 3 been reflected in the price of the
14 Company's common stock?

15 A. Yes, and this is reflected in my Schedule 4 which shows the prices
16 received by the Company after underwriting costs for each sale of its
17 common stock since 1968. It can be seen that since 1973, the market
18 price for our stock has been below book value. With the continuation
19 of inadequate earnings on equity and without further rate relief this
20 condition will not correct itself. At December 31, 1982, our common
21 stock was selling at 78.5% of book value. This is in the lower range
22 of the averages when compared to other utility companies.

23

24 Q. Mr. Peterson, what has been the effect of selling additional shares of
25 common stock below book value?

1 A. The effect has been substantial confiscation of stockholder equity.
2 Beginning with October 1974 sale of common stock, the Company has
3 sold 54.1 million shares of stock below book value. Thus 45% of the
4 Company's total shares outstanding have been sold below book
5 value. The aggregate effect of selling these issues below book value
6 has been dilution of the investment of holders of common stock by
7 14.2%. Had the Company sold these shares at book value, an
8 additional \$350 million would have been raised from sales of the same
9 number of shares, dilution of assets would not have resulted, and the
10 cost of capital would be lower, resulting in less need for rate
11 increases. Both the customer and the stockholder have been injured
12 by these circumstances.

13

14 Q. Mr. Peterson, will you discuss Schedule 5.

15 A. Page 1 of Schedule 5 shows the interest coverage test under the
16 indenture of mortgage which governs the issuance of the Company's
17 mortgage bonds. The indenture provides that additional bonds may be
18 issued only if net earnings, as defined, are at least two times the
19 annualized interest charges on all outstanding bonds, plus the annual
20 interest charges on the additional bonds proposed to be issued at the
21 time. Page 1 also shows that following the issuance of \$85 million
22 Series W 7 1/8% Bonds in January 1969, thirteen years ago, Net
23 Earnings were 4.15 times Annual Interest Charges.

24 In 1981, after the sale of \$100 million Series A Bonds, Net
25 Earnings had decreased to 2.73 times annual interest charges, and has

1 improved to 3.36 times as of December 31, 1982. This improvement
2 is largely a result of a reduction in the amount of bonds sold each
3 year.

4
5 Q. Please explain Page 2 of Schedule 5.

6 A. Page 2 shows the Ratio of Earnings to Fixed Charges Based on the
7 Securities and Exchange Commission (S.E.C.) Formula.

8 The security-rating agencies and bond purchasers rely heavily
9 upon this coverage test as one of the criteria for evaluating bond
10 risks. This coverage test includes interest on all debt including short-
11 term debt and also includes lease rentals, as shown on Schedule 5. At
12 the time of issue of the Series W Bonds in January 1969, the S.E.C.
13 coverage of actual fixed charges was 4.52 times, while such coverage
14 proformed for debt to be outstanding after the sale of the securities
15 was 3.72 times. As of June 30, 1974, the coverage had decreased to
16 2.01 times and was 1.73 times after giving effect to the annual
17 interest requirements on all outstanding debt. At December 31,
18 1981, coverage had decreased to 1.99 times and 1.89 times after
19 giving effect to annual interest requirements on all outstanding debt.
20 This coverage has improved to 2.31 times and 2.46 times at year end
21 December 31, 1982. Continued improvement of this coverage can be
22 greatly enhanced by a favorable response from this Commission and
23 will be rewarded by lower interest rates in the future.

24
25 Q. Please explain the coverage provision with respect to preferred

1 stock.

2 A. The Vepco charter provides that no additional preferred shares may
3 be issued unless earnings, as defined, shall have been at least $1\frac{1}{2}$
4 times interest charges on all debt and dividend requirements on
5 preferred stock, except by the consent of the holders of a majority of
6 the outstanding shares.

7 The Preferred Stock Coverage Test is shown on Page 3 of
8 Schedule 5. Under that test, based on the 12-month period ended
9 December 31, 1976, the ratio was 1.60 times interest charges, it
10 decreased to 1.42 times at December 31, 1979 and remained below
11 the $1\frac{1}{2}$ times interest charges until the spring of 1982; therefore the
12 Company could not sell additional preferred stock for most of 1979
13 through 1981. At June 30, 1982 the rate was 1.60 times, and was 1.73
14 times at December 31, 1982. The improvement in this coverage test
15 is encouraging, but its continuation is dependent upon favorable rate
16 treatment. If this trend continues the Company will be able to retain
17 the use of this vehicle through which it may acquire needed capital.

18

19 Q. You have referred to the security-rating agencies. Please identify
20 them and discuss their significance.

21 A. Moody's Investors Service and Standard and Poor's Corporation are
22 two major rating agencies that rate the quality of the senior
23 securities of Vepco and other companies for the investment market.
24 These agencies provide the investing public with a rating which is
25 designed to reflect their opinions on the degree of probability, over

1 the longer term, of punctual payment of interest and dividends and
2 principal by the Company. These ratings are made based on in-depth
3 analysis of the factors which contribute to security of investment.

4 Criteria the agencies consider in the rating decisions are:

5 Soundness of the regulatory and political climate in which
6 the Company operates.

7 Effectiveness of the Company's management.

8 Method of recouping increases in fuel costs.

9 Regulatory treatment of Construction Work in Progress
and Allowance For Funds Used During Construction.

10 Projected construction expenditures.

11 Projected growth.

12 Return on equity and rate base.

13 Future financing needs.

14 Internal cash generation.

15 Vepco First Mortgage Bonds are currently rated "A-2" by Moody's and
16 "A" by Standard & Poor's and preferred stock is rated "Baa-2" by
17 Moody's and "BBB" by S & P.

18

19 Q. How do the relevant financial data for Vepco compare with the data
20 for other utilities.

21 A. Shown on Schedule 6 are four key financial ratios for Vepco and the
22 average of those ratios for other companies in the electric utility
23 industry at December 31, 1982. These indicia of financial health
24 indicate, in all cases, that Vepco is below the average of the industry.

25

1 Q. What is the significance of these comparisons?

2 A. It is clear that, despite improvements, Vepco's financial strength is
3 not what it should be. Indeed, the Company was informed by S & P in
4 1982 that its present ratings are in jeopardy. A downrating could be
5 very costly to the Company and its customers. Since the spread
6 between the average "A" and "Baa" new issues as of the end of the
7 test year 1982 was about 77 basis points, the interest cost on \$100
8 million of mortgage bonds over thirty years would increase about
9 \$23.1 million.

10

11 Q. What must occur to prevent a downrating of the Company's senior
12 capital?

13 A. Clearly the financial data shown on Schedule 6 must continue to
14 improve substantially. While these factors will be helped by the more
15 efficient operations to which the Company has been dedicated, the
16 single most important factor overall is the response of the regulatory
17 authorities to our requests for rate increases. Timely and adequate
18 rate increases are paramount to the necessary improved financial
19 performance.

20

21 Q. Mr. Peterson, you have stated that one of the factors that affect the
22 Company's efforts to attain adequate earnings is inflation. Please
23 discuss the effect of inflation on the Company's ability to earn its
24 authorized rate of return.

25 A. In regulatory jurisdictions like Virginia, where a prior test year has

1 been traditionally used for establishing future levels of income, the
 2 length of the regulatory process causes a gap between the test year
 3 used for establishing levels of expenses and the time when the rates
 4 based on those expenses actually go into effect. During such periods,
 5 all of the Company's expenses are subject to the same inflationary
 6 pressures that beset any other business, and the rate relief
 7 determined by reference to the historical test year invariably falls
 8 short of the increase in expenses actually incurred.

9 This can be shown by a comparison between the allowed return
 10 on equity (ROE) in Virginia and the realized ROE over the last ten
 11 years.

		Rate of Return on Common Equity		
		Virginia Jurisdictional Allowed	Earned Per Books Year End	Basis Points Differential
14	1982	15.00%	10.12%	488
15	1981	15.00	9.25	575
16	1980	13.50	9.90	360
17	1979	13.50	8.16	534
18	1978	13.50	9.24	426
19	1977	13.50	9.51	399
20	1976	13.50	9.21	429
21	1975	13.50	9.80	370
22	1974	13.00	8.09	491
23	1973	13.00	10.51	249
24	Total			<u>4,321</u>
25	Average for 10 years			<u><u>432</u></u>

1 The average shortfall between allowed and realized over the
2 ten year period has been 432 basis points.

3 Clearly all through the last ten years this has been a major
4 problem.

5

6 Q. Mr. Peterson, please summarize your testimony.

7 A. The Company requires rate relief from all jurisdictions to improve its
8 financial position. Continued inadequate rate relief will undoubtedly
9 make it more difficult or impossible to raise the dollars necessary to
10 continue the Company's capital programs and also maintain the
11 financial health of the Company. The Company and the financial
12 community need to receive a strong, positive response from this the
13 most important jurisdiction regulating the Company's rates. The
14 long-term best interests of our customers, which are the
15 responsibility of this Commission, will be served if this rate increase
16 is granted.

17

18 Q. Does this conclude your pre-filed testimony?

19 A. Yes, it does.

20

21

22

23

24

25

QUALIFICATIONS OF O. J. PETERSON, III

1 Mr. Peterson graduated from the University of North Carolina
2 at Chapel Hill with the degree of Bachelor of Science in Business
3 Administration in 1962. He was employed by Carolina Telephone and
4 Telegraph Company, Tarboro, North Carolina, in 1962, and served
5 that Company in various supervisory capacities until 1966. From
6 1966 until May of 1970, Mr. Peterson served that Company as
7 Financial Staff Assistant reporting directly to the Vice President-
8 Finance. During his employment with Carolina Telephone and
9 Telegraph Company, he participated actively in the sale of
10 debentures, convertible debentures and common stock aggregating
11 \$90 million. In May of 1970, Mr. Peterson was employed by Vepco as
12 Executive Assistant-Finance, was promoted to Assistant Treasurer in
13 June 1971. He was appointed Treasurer October 1, 1975, and was
14 promoted to his present position January 1, 1978.

15 Mr. Peterson is the Company's Chief Financial Officer. Since
16 joining Vepco his principal assignments have been in the planning and
17 execution of all the Company's financings, including the public and
18 private sale of mortgage bonds, preferred stock, preference stock,
19 common stock, the negotiation of long-term bank loans and the sale
20 of pollution-control revenue bonds. These financings aggregate in
21 excess of \$5 billion dollars at December 31, 1982. He has also
22 participated in lease financings aggregating about \$200 million,
23 including the sale and lease-back of twenty-eight combustion
24 turbines, the sale and lease-back or similar financings for both cores
25 of nuclear fuel at our Surry Nuclear Power Plant and sale and lease-

1 back financings of real estate and mining equipment.

2 In addition to long-term financings, he is responsible for the
3 Company's bank and investor relations, short-term bank borrowings,
4 short-term pollution control note sales, commercial paper sales
5 through brokers in the money markets, and direct commercial paper
6 sales to investors by the Company in our operating area. As a result
7 of all of these activities, he is in frequent contact with financial
8 institutions and investment bankers.

9 Mr. Peterson has testified for the Company in rate proceedings
10 before this Commission, the North Carolina Utilities Commission, the
11 Public Service Commission of West Virginia, the Federal Energy
12 Regulatory Commission, and on financial matters before the Nuclear
13 Regulatory Commission.

14 Mr. Peterson has participated in financial seminars sponsored
15 by Irving Trust Company, The Edison Electric Institute, The Atomic
16 Industrial Forum and the Southeastern Electric Exchange, and has
17 served in positions or on committees of the Southeastern Electric
18 Exchange, and the Atomic Industrial Forum.

19

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Virginia Electric and Power Company
Capital Structure and Cost of Capital With
Cost of Common Equity at 15%
December 31, 1982

69

Vepco-OJP
Schedule 1

(Thousands of Dollars)

	(Col. A) Amount Outstanding	(Col. B) Percentage	(Col. C) Annualized Cost	(Col. D) Embedded Cost	(Col. E) Return Component
Long Term Debt:					
1 Mortgage Bonds	\$2,447,734	37.13%	\$219,023	8.95%	3.32%
2 Convertible Debentures	49,990	.76	1,845	3.69	.03
3 Pollution Control Rev. Bonds	42,500	.65	3,034	7.14	.05
4 Pollution Control Notes	22,000	.33	2,292	10.42	.03
5 Bank Loans	392,500	5.95	40,731	10.38	.62
6 Total	<u>2,954,724</u>	<u>44.82</u>	<u>266,925</u>	<u>9.03</u>	<u>4.05</u>
Other Long Term Debt:					
7 Bath County-Project Financing	250,000	3.79	22,751	9.10	.34
8 Total	<u>3,204,724</u>	<u>48.61</u>	<u>289,676</u>	<u>9.04</u>	<u>4.39</u>
9 Short Term Debt *	90,125	1.37	10,686	11.86	.16
10 Customer Deposits	21,775	.33	1,742	8.00	.03
11 Total Debt	<u>3,316,624</u>	<u>50.31</u>	<u>302,104</u>	<u>9.11</u>	<u>4.58</u>
12 Preferred and Preference Stock	673,301	10.21	57,298	8.51	.87
13 Total Senior	<u>3,989,925</u>	<u>60.52</u>	<u>\$359,402</u>	<u>9.01</u>	<u>5.45</u>
Subscription Received on					
14 Capital Stock	3,114	.05		8.00	
Common Equity:					
15 Common Stock	1,642,714	24.92		15.00	3.74
16 Retained Earnings	519,187	7.87		15.00	1.18
17 Other Paid-in Capital	23,680	.36			
18 Total	<u>2,185,581</u>	<u>33.15</u>			<u>4.92</u>
Accumulated Job Development					
19 Deferred Investment Tax Credit	103,409	1.57		<u>10.54%</u>	.17%
20 Customer Advances for Construction	2,104	.03			
21 Provision for Levelizing Payment of lease Turbines	18,448	.28			
Accumulated Deferred Income Taxes:					
22 Liberalized Depreciation	254,750	3.87			
23 Cost of Removal, taxes and benefits- plan, cost capitalized	43,668	.66			
24 Accumulated deferred taxes-other	1,052	.02			
25 Accelerated Amortization	6,992	.11			
26 Leaseback	(2,628)	(.04)			
27 Owned Nuclear Fuel - N.A. 1 & 2	(6,951)	(.11)			
28 Owned Nuclear Fuel - Surry	(5,370)	(.08)			
29 Variable Price Interest	4,164	.06			
Preliminary Operations Fuel Expenses					
30 North Anna 2	(9,378)	(.14)			
31 Leased Nuclear Fuel - Surry	4,012	.06			
32 Customer Accounts Receivable	(570)	(.01)			
33 Total	<u>\$6,592,322</u>	<u>100.00%</u>			<u>10.54%</u>

* Weighted Average as noted in Annual Report, net of short-term investments.

Virginia Electric and Power Company
Capital Structure and Cost of Capital With
Cost of Common Equity at 16%
(Estimated) December 31, 1983

(Thousands of Dollars)

	(Col. A) Amount Outstanding	(Col. B) Percentage	(Col. C) Annualized Cost	(Col. D) Embedded Cost	(Col. E) Return Component
Long Term Debt:					
1 Mortgage Bonds	\$2,512,536	35.91%	\$228,038	9.08	3.26%
2 Convertible Debentures	49,990	.71	1,845	3.69	.03
3 Pollution Control Rev. Bonds	40,250	.58	2,840	7.06	.04
4 Pollution Control Notes	22,000	.31	2,292	10.42	.03
5 Bank Loans	375,000	5.36	39,188	10.45	.56
6 Total	<u>2,999,776</u>	<u>42.87</u>	<u>274,203</u>	9.14	3.92
Other Long Term Debt:					
7 Bath County-Project Financing	250,000	3.57	20,000	8.00	.29
8 Total Long-Term	<u>3,249,776</u>	<u>46.44</u>	<u>294,203</u>	9.05	4.21
9 Short Term Debt	80,983	1.16	6,479	8.00	.09
10 Customer Deposits	22,375	.32	1,969	8.80	.03
11 Total Debt	<u>3,353,134</u>	<u>47.92</u>	<u>302,651</u>	9.03	4.33
12 Preferred and Preference Stock	668,318	9.55	56,874	8.51	.81
13 Total Senior Debt	<u>4,021,452</u>	<u>57.47</u>	<u>\$359,525</u>	8.94	5.14
Subscription Received on					
14 Capital Stock	3,000	.04		8.00	-
Common Equity:					
15 Common Stock	1,775,442	25.37		16.00	4.06
16 Retained Earnings	563,976	8.06		16.00	1.29
17 Other Paid-in Capital	22,844	.33		-	-
18 Total	<u>2,362,262</u>	<u>33.76</u>			5.35
Accumulated Job Development					
19 Deferred Investment Tax Credit	243,127	3.48%		<u>10.87%</u>	.38
20 Customer Advances for Construction	2,179	.03			
21 Provision for Levelizing Payment of lease Turbines	16,945	.24			
Accumulated Deferred Income Taxes:					
22 Liberalized Depreciation	300,373	4.29			
23 Cost of Removal, taxes and benefits- plan, cost capitalized	50,275	.72			
24 Accumulated deferred taxes-other	-	-			
25 Accelerated Amortization	5,508	.08			
26 Leaseback	(1,159)	(.02)			
27 Owned Nuclear Fuel - N.A. 1 & 2	(1,783)	(.02)			
28 Owned Nuclear Fuel - Surry	(5,370)	(.08)			
29 Variable Prime Interest	6,119	.09			
Preliminary Operations Fuel Expenses					
30 North Anna 2	(9,042)	(.13)			
31 Leased Nuclear Fuel - Surry	4,012	.06			
32 Customer Accounts Receivable	(570)	(.01)			
33 Total	<u>\$6,997,328</u>	<u>100.00%</u>			<u>10.87%</u>

VIRGINIA ELECTRIC AND POWER COMPANY

EMBEDDED COST OF LONG-TERM DEBT AND PREFERRED STOCK, AND RETURN ON COMMON EQUITY

1971 - 1982 and Estimated 1983

Line Number	Description	Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H	Column I	Column J	Column K	Column L	Column M
		1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	Estimated 1983
Long-Term Debt:*														
1	Mortgage Bonds	5.99%	6.11%	6.10%	6.77%	7.62%	7.79%	7.86%	8.03%	8.28%	8.44%	8.91%	8.95%	9.08%
2	Convertible Debentures	3.69%	3.69%	3.69%	3.69%	3.69%	3.69%	3.69%	3.69%	3.69%	3.69%	3.69%	3.69%	3.69%
3	Sinking Fund Debentures	3.53%	3.53%	3.53%										
4	Pollution Control Bonds		5.74%	5.74%	5.38%	7.38%	7.40%	7.40%	7.40%	7.34%	7.28%	7.21%	7.14%	7.06%
5	Bank Notes and Loans		7.75%	8.00%	8.51%	8.44%	8.43%	8.35%	8.63%	8.96%	9.83%	11.67%	10.38%	10.45%
6	Bath County										19.13%	13.53%	9.10%	8.00%
7	Total Long-Term Debt	<u>5.86%</u>	<u>6.05%</u>	<u>6.13%</u>	<u>6.90%</u>	<u>7.59%</u>	<u>7.75%</u>	<u>7.81%</u>	<u>7.99%</u>	<u>8.26%</u>	<u>8.54%</u>	<u>9.28%</u>	<u>9.04%</u>	<u>9.05%</u>
8	Preferred and Preference Stock*	<u>6.40%</u>	<u>6.77%</u>	<u>6.88%</u>	<u>7.16%</u>	<u>7.73%</u>	<u>8.01%</u>	<u>8.43%</u>	<u>8.49%</u>	<u>8.51%</u>	<u>8.51%</u>	<u>8.51%</u>	<u>8.51%</u>	<u>8.51%</u>
9	Total Senior Capital**	<u>5.94%</u>	<u>6.19%</u>	<u>6.30%</u>	<u>6.96%</u>	<u>7.62%</u>	<u>7.78%</u>	<u>7.91%</u>	<u>8.09%</u>	<u>8.52%</u>	<u>9.35%</u>	<u>9.61%</u>	<u>9.01%</u>	<u>8.94%</u>
10	Return on Common Equity*	10.26%	10.77%	10.54%	8.09%	9.80%	9.21%	9.51%	9.24%	8.16%	9.90%	9.25%	10.12%	-

* Embedded costs of long-term debt and preferred stock, and return actually earned on common equity excluding Accumulated Job Development Deferred Investment Tax Credit are based on amounts outstanding at year end.

** Short-term debt included for test year and subsequent periods, as shown in cost of capital statement Schedules 1 and 2.

21

VIRGINIA ELECTRIC AND POWER COMPANYSALES OF COMMON STOCK

<u>Column A</u>	<u>Column B</u>	<u>Column C</u>	<u>Column D</u>	<u>Column E</u>
<u>Year of Sale</u>	<u>Number Shares</u>	<u>Price Per Share</u>	<u>Book Value at Time of Sale</u>	<u>Sale Price to Book Value</u>
1968	2 million	\$ 26.13	\$13.27	196.9%
1970	3 million	23.90	15.30	156.2
1971	4 million	19.12	16.60	115.2
1972	5 million	17.53	17.47	100.3
1973	5 million	18.15	18.14	100.1
1974	6.6 million	8.325	18.56	44.9
1975 (June)	4 million	12.62	18.18	69.4
1975 (November)	5 million	12.70	18.11	70.1
1976	5 million	14.775	18.26	80.9
1977	5 million	14.08	18.67	75.4
1978	5 million	13.655	19.25	70.9
1979	6 million	10.675	19.38	55.1
1980	5 million	10.79	18.60	60.5
1981	2 million*	11.145	18.44	60.4
1982 (February)	5.5 million	11.535	18.98	60.8
1982 (November)	5 million	13.80	18.07	76.4

NOTE: Excludes shares purchased for ADR and Savings Plan below book value.

*Private Placement.

Vepco-OJP
Schedule 5-1

VIRGINIA ELECTRIC AND POWER COMPANY
INTEREST COVERAGE TEST UNDER INDENTURE OF MORTGAGE

<u>Series and Issue Date</u>	<u>Principal Amount</u>	<u>Earnings As Defined(a)</u>	<u>Annual Interest Charges</u>	<u>Interest Coverage</u>
(Thousands of Dollars)				
W 7 1/8% January, 1969	\$ 85,000	\$119,777	\$ 28,835	4.15(b)
X 7 3/4% June, 1969	75,000	121,809	34,648	3.52
Y 9% April, 1970	85,000	133,002	42,298	3.14
Z 8 7/8% September, 1970	85,000	132,381	49,764	2.66
AA 7 3/8% March, 1971	90,000	140,092	56,402	2.48
BB 7 1/2% September, 1971	50,000	135,808	60,152	2.26
CC 7 3/8% June, 1972	100,000	143,627	67,527	2.13
DD 10 1/2% July, 1974	75,000	191,993	75,174	2.55
EE 11% July, 1974	100,000	191,993	86,174	2.23
FF 11% February, 1975	150,000(c)	223,326	102,674	2.18
Pollution Control Series A September, 1975	26,000	320,341	113,071	2.83
GG 10% November, 1975	100,000	343,005	113,071	3.03
Actual at December 31, 1975		321,609	113,071	2.84
HH 9 1/4% March, 1976	100,000	330,221	122,321	2.70
Pollution Control Series B May, 1976	20,000	339,308	123,671	2.74
II 8 3/4% September, 1976	100,000	335,843	132,421	2.54
Actual at December 31, 1976		356,745	132,421	2.69
JJ 8 5/8% March, 1977	150,000	358,524	144,451	2.48
Actual at December 31, 1977		382,616	144,451	2.65
KK 8.95% March, 1978	55,000	388,494	148,466	2.62
Pollution Control Series C May, 1978	8,000	403,534	148,958	2.71
LL 9 5/8% July, 1978	150,000	399,631	163,096	2.45
Actual at December 31, 1978		444,649	163,096	2.73
A 10.25% April, 1979	100,000	439,682	172,438	2.55
B 9.95% October, 1979	135,000	449,495	184,196	2.44
Actual at December 31, 1979		454,080	184,195	2.47
A 12.5% July, 1980	75,000	471,644	182,728	2.58
Actual at December 31, 1980		535,877	191,210	2.80
Series "A" April, 1981	100,000	562,584	205,859	2.73
Actual at June 30, 1981		586,013	205,855	2.85
Actual December 31, 1981		622,848	211,165	2.95
Actual June 30, 1982		694,525	209,662	3.31
Actual December 31, 1982		727,793	216,366	3.36

NOTES: (a) Net earnings for Series DD and EE Bonds based on 12 months ended May 31, 1974, net earnings for other issues based on 12 months ended with second month preceding date of bond issue.
 (b) Times Interest Earned.
 (c) Total amount of series, \$5,000,000 of which were not delivered until August 1975.

VIRGINIA ELECTRIC AND POWER COMPANYRATIO OF EARNINGS TO FIXED CHARGES BASED ON S.E.C. FORMULA

<u>Series and Issue Date</u>	<u>Principal Amount</u>	<u>Earnings As Defined(a)</u>	<u>Fixed Charges At Time Of Bond Issue (a)</u>	<u>Fixed Charges Pro Forma For Bond Issue (b)</u>	<u>Ratio At Time Of Bond Issue (a)</u>	<u>Ratio Pro Forma For Bond Issue (b)</u>
(Thousands of Dollars)						
W 7 1/8% January, 1969	\$ 85,000	\$119,712	\$ 26,492	\$ 32,179	4.52	3.72
X 7 3/4% June, 1969	75,000	122,195	28,585	38,160	4.27	3.20
Y 9% April, 1970	85,000	132,805	36,187	46,140	3.67	2.88
Z 8 7/8% September, 1970	85,000	132,088	42,197	54,223	3.13	2.44
AA 7 3/8% March, 1971	90,000	143,437	48,681	60,696	2.95	2.36
BB 7 1/2% September, 1971	50,000	144,030	56,026	63,952	2.57	2.25
CC 7 3/8% June, 1972	100,000	158,971	66,604	75,986	2.39	2.09
Actual at June 30, 1974		217,921	108,485	126,237	2.01	1.73
DD 10 1/2% July, 1974	75,000	220,684	103,622	122,078	2.13	1.81
EE 11% July, 1974	100,000	220,684	103,622	126,649	2.13	1.74
Actual at December 31, 1974		233,917	125,018	142,330	1.87	1.64
FF 11% February, 1975	150,000(c)	233,917	125,018	153,452	1.87	1.52
Pollution Control Series A September, 1975	26,000	297,073	141,907	150,778	2.09	1.97
GG 10% November, 1975	100,000	327,406	144,794	157,562	2.26	2.08
Actual At December 31, 1975		332,820	150,566	153,264	2.21	2.17
HH 9 1/4% March, 1976	100,000	332,820	150,566	161,026	2.21	2.07
II 8 3/4% September, 1976	100,000	344,508	155,385	173,652	2.22	1.98
Actual at December 31, 1976		378,252	162,707	168,061	2.32	2.25
JJ 8 5/8% March, 1977	150,000	378,252	162,707	181,467	2.32	2.08
Actual at December 31, 1977		434,094	183,956	190,869	2.36	2.27
KK 8.95% March, 1978	55,000	434,094	183,956	195,750	2.36	2.22
Pollution Control Series C May, 1978	8,000	448,354	187,925	195,379	2.39	2.29
LL 9 5/8% July, 1978	150,000	453,492	191,972	212,213	2.36	2.14
Actual at December 31, 1978		480,770	202,869	208,709	2.37	2.30
A 10.25% April, 1979	100,000	475,408	207,586	226,592	2.29	2.10
B 9.95% October, 1979	135,000	485,877	218,438	252,226	2.22	1.93
Actual at December 31, 1979		494,170	227,591	252,892	2.17	1.95
A 12.5% July, 1980	75,000	515,825	252,408	271,088	2.04	1.90
Actual at December 31, 1980		588,820	276,480	312,155	2.13	1.89
Actual at June 30, 1981		641,830	305,502	352,626	2.10	1.82
Actual at December 31, 1981		682,388	343,223	361,454	1.99	1.89
Actual at June 30, 1982		760,393	356,757	356,011	2.13	2.14
Actual December 31, 1982		788,124	341,679	319,861	2.31	2.46

(a) Based on 12 months ended within three months preceding date of bond issue.

(b) Gives effect to the annual interest requirements on all debt to be outstanding, including new bonds and notes payable estimated to be outstanding after receipt of the proceeds from the sale of the new bonds and the application thereof to the reduction of notes payable.

(c) Total amount of Series, \$5,000,000 of which were not delivered until August 1975.

VIRGINIA ELECTRIC AND POWER COMPANY

PREFERRED STOCK COVERAGE TEST

(Thousands of Dollars)

	<u>Column A</u>	<u>Column B</u>	<u>Column C</u>	<u>Column D</u>	<u>Column E</u>	<u>Column F</u>	<u>Column G</u>	<u>Column H</u>
	12 Months Ended							
	<u>December 1976</u>	<u>December 1977</u>	<u>December 1978</u>	<u>December 1979</u>	<u>December 1980</u>	<u>December 1981</u>	<u>June 30, 1982</u>	<u>December 1982</u>
a. Net income for 12 months ended	\$166,786	\$189,793	\$203,864	\$196,467	\$241,620	\$237,780	\$267,390	\$278,589
Interest charges on all indebtedness and dividends on all Shares of Senior Stock to be retired	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>
Sum	<u>166,786</u>	<u>189,793</u>	<u>203,864</u>	<u>196,467</u>	<u>241,620</u>	<u>237,780</u>	<u>267,390</u>	<u>278,589</u>
Dividend requirements on Senior Stock	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>	<u>NONE</u>
Remainder	<u>\$166,786</u>	<u>\$189,793</u>	<u>\$203,864</u>	<u>\$196,467</u>	<u>\$241,620</u>	<u>\$237,780</u>	<u>\$267,390</u>	<u>\$278,589</u>
b. Annual Dividend Requirements:								
Preferred Stock	\$ 39,625	\$ 44,817	\$ 47,933	\$ 50,331	\$ 50,229	\$ 50,054	\$ 50,054	\$ 49,879
Parity Stock	-	-	-	-	-	-	-	-
New Preferred	-	-	-	-	-	-	-	-
Total	<u>\$ 39,625</u>	<u>\$ 44,817</u>	<u>\$ 47,933</u>	<u>\$ 50,331</u>	<u>\$ 50,229</u>	<u>\$ 50,054</u>	<u>\$ 50,054</u>	<u>\$ 49,879</u>
c. The remainder in (a) is more than 2 1/2 times the total annual dividend requirement	<u>4.21</u>	<u>4.23</u>	<u>4.25</u>	<u>3.90</u>	<u>4.81</u>	<u>4.75</u>	<u>5.34</u>	<u>5.59</u>
d. Net income in (a) above Interest charges deducted in arriving at net income	<u>166,786</u>	<u>189,793</u>	<u>203,864</u>	<u>196,467</u>	<u>241,620</u>	<u>237,780</u>	<u>267,390</u>	<u>278,589</u>
	<u>154,301</u>	<u>173,713</u>	<u>190,681</u>	<u>215,823</u>	<u>261,953</u>	<u>322,699</u>	<u>333,053</u>	<u>322,173</u>
Total	<u>\$321,087</u>	<u>\$363,506</u>	<u>\$394,545</u>	<u>\$412,290</u>	<u>\$503,573</u>	<u>\$560,479</u>	<u>\$600,443</u>	<u>\$600,762</u>
e. Annual interest and dividend requirements:								
All outstanding debt	\$160,631	\$178,018	\$195,819	\$239,028	\$293,545	\$333,811	\$326,045	\$297,497
The new bonds	-	-	-	-	-	-	-	-
Preferred stock outstanding	39,625	44,817	47,933	50,331	50,229	50,054	50,054	49,879
Parity stock outstanding	-	-	-	-	-	-	-	-
Senior stock outstanding	-	-	-	-	-	-	-	-
New preferred	-	-	-	-	-	-	-	-
Total	<u>\$200,256</u>	<u>\$222,835</u>	<u>\$243,752</u>	<u>\$289,359</u>	<u>\$343,774</u>	<u>\$383,865</u>	<u>\$376,099</u>	<u>\$347,376</u>
f. The total of (d) shall be more than 1 1/2 times the total of (e)	<u>1.60</u>	<u>1.63</u>	<u>1.62</u>	<u>1.42</u>	<u>1.46</u>	<u>1.46</u>	<u>1.60</u>	<u>1.73</u>

VIRGINIA ELECTRIC AND POWER COMPANYKEY FINANCIAL DATADECEMBER 31, 1982

	<u>Average of Electric Utilities*</u>	<u>Vepco</u>
Return on Average Equity	13.8%	10.7%
Internal Cash Generation	45.8%	40.9%
Capital Structure - Common Equity Ratio	37.8%	36.1%
Pre-Tax Interest Coverage	2.68x	2.39x

Source: Electric Utility Industry, Selected Financial Ratios, by Goldman Sachs

* Some estimated figures

TESTIMONY OF JAMES P. CARNEY
FOR VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE 8300 29

1 Q. Would you please state your name and present position?

2 A. My name is James P. Carney, and I am currently Director-Economic Analysis,
3 Forecasting and Economic Analysis Department, Virginia Electric and Power
4 Company. A description of my background and experience is contained on
5 Appendix A.

6
7 Q. What is the purpose of your testimony?

8 A. I have been asked to study and make a recommendation as to the cost of
9 equity capital to Vepco.

10

11 Q. Have you prepared an exhibit in support of your testimony?

12 A. Yes, Exhibit VEPCO-JPC___, consisting of 15 Schedules, 4 Attachments and
13 one Appendix was prepared by me or under my supervision and is accurate to
14 the best of my knowledge.

15

16 Q. Would you describe briefly the role and purpose of the return on equity
17 capital?

18 A. The return on equity capital is a component of the overall rate of
19 return. The overall rate of return provides compensation to the suppliers
20 of financial capital for the use of their funds. The return to these
21 investors, plus the other costs of service, determine the revenue level
22 upon which rates to customers are based.

1 In providing investors compensation for the use of their funds, the
2 rate of return serves as a guide to the allocation of resources to the
3 industry, and for this reason an adequate rate of return is important.
4 Utilities in discharging their obligation to serve the public must respond
5 to increased demands for their services by investing in additional plant
6 and equipment and replacing old and obsolete equipment. The utility will
7 attempt to do so in a manner that will minimize the cost of production
8 over time. Such least cost approach however, often requires substantial
9 initial expenditures, making it necessary to raise large amounts of
10 capital. It is a well accepted principle in capital budgeting theory that
11 the value in use of a real asset must at least equal the current cost of
12 the funds used to finance the investment or the asset will not be
13 purchased. If the rate of return is held below that which the investor
14 requires by forces external to the firm, the investor will be unwilling to
15 supply sufficient funds to cover the firm's cost of purchasing the
16 assets. Sub-optimal investment will result. Thus, capital resources
17 which would otherwise be employed in the utility industry will be diverted
18 elsewhere.

19

20 Q. Given that the return on capital provides a signal for resource
21 allocation, what criteria should one apply in determining the
22 reasonableness of the rate of return?

23 A. The rate of return on capital must be "fair" and "reasonable" in line with
24 the following criteria:

25 1. It should provide the investor with compensation commensurate with

1 that earned by investing funds in enterprises of comparable risk, and
2 2. It should be sufficient to allow the utility to compensate the
3 investor to a degree that will insure the utility's ability to
4 attract future capital on reasonable terms.

5
6 Q. Is the "fair" rate of return fixed over time or can it vary?

7 A. The fair rate of return is not fixed over time; it varies with the
8 alternative investment opportunities available to the investor, as well as
9 with the perceived risk of a particular investment. As the economy
10 changes over time so do the alternatives to which the investor can direct
11 his funds. Thus, the rate of return is an opportunity cost concept; it
12 must change as the opportunities of the investor change. In particular,
13 for a regulated utility whose revenue requirements are based, in part, on
14 the rate of return, a level of earnings sufficient to meet the above two
15 criteria must be realized. They must be realized over the period of time
16 in which the particular rate schedules based on this rate of return will
17 be in effect.

18
19 Q. You have said that the investor must be compensated for providing funds to
20 the utility. For what, exactly, must the investor be compensated?

21 A. In providing funds to the utility, the investor has decided to forego
22 current consumption in favor of future consumption. However, he will
23 postpone his current consumption only if by doing so his future
24 consumption is greater than it would have been had he not invested his
25 funds. The rate at which an investor will trade current for future

1 consumption is his discount rate. Unless a particular investment earns
2 this discount rate, the individual will not be willing to forego current
3 for future consumption in order to invest in this particular project. The
4 investor will either look elsewhere for alternative opportunities, or use
5 his funds for current consumption.

6 Furthermore, even without inflation risk, there is no guarantee that
7 the funds the investor provides will be employed in a manner that will
8 generate income sufficient to provide a return equal to his discount
9 rate. There is always uncertainty surrounding the income earning ability
10 of the assets purchased with investor's funds. Again, an investor's
11 expectations may not be realized. In view of this latter uncertainty, as
12 well as the inflation risk, the investor will seek a margin of safety over
13 and above that necessary to provide compensation for foregone current
14 consumption. The greater the uncertainty over the income producing
15 ability of the investment, the larger the margin of safety the investor
16 will require. The return needed to induce an investor to provide funds to
17 a firm to compensate for the deferral of consumption plus the uncertainty
18 surrounding the income earning capability of the assets is the investor's
19 real rate of return. When we adjust the real rate of return for the
20 effects of inflation we arrive at the investor's required rate of return.

21

22 Q. Given that firms issue both debt as well as equity instruments, are there
23 any differences in risks between them?

24 A. Yes, there are. The uncertainty surrounding the income earning ability of
25 the assets of a firm constitutes what is called business risk.

1 Furthermore, there is a risk associated with holding various types of
2 financial instruments. It is referred to as financial risk. Holders of
3 debt instruments have first claim to earnings. The return provided to
4 them is contractual in nature. Common equity holders, at the other
5 extreme, have lowest priority claim to earnings. Their return is the
6 residual remaining after all fixed contractual obligations have been
7 paid. It is the uncertainty over the size of the residual earnings that
8 give rise to greater financial, hence overall, risk to equity holders
9 relative to holders of debt.

10
11 Q. How then does an investor in common stock guard against these risks when
12 he supplies funds to a firm?

13 A. He does so by offering to purchase the stock at a price he feels will
14 yield his required return on the amount invested. When purchasing a share
15 of common stock the investor anticipates an income stream comprised of two
16 components: 1) dividends and 2) a capital gain (or loss) upon the sale of
17 the stock. In order to ensure that this expected income stream yields the
18 investor's required return, the stream will be discounted at a rate equal
19 to the required return, and the investor will offer to purchase the stock
20 at this discounted value. The price the investor expects to receive upon
21 the sale of the stock to a future investor will equal the discounted value
22 of the income stream the future investor expects to receive.

23
24 Q. Do these considerations lead to any type of methodology which can be used
25 to estimate the investor's required return?

1 A. Yes. The well-known "Discounted Cash Flow" (DCF) equation can be used for
2 this purpose, as is demonstrated in Appendix B. The DCF equation states
3 that the current price of a share of stock is equal to the expected
4 dividend per share divided by the difference between the investor's
5 required return and the expected growth rate in dividends per share:

6

7

$$P_0 = D/(k-g)$$

8

9

where

10

P_0 = stock price (current)

11

D = expected dividends per share

12

k = investor's required return

13

g = expected growth rate in dividends per share

14

15

The DCF equation can be rearranged to give:

16

$$k = (D/P_0) + g$$

17

18

19

20

21

22

23

24

25

Q. Is the DCF methodology consistent with the fair and reasonable criteria

1 which you mentioned earlier?

2 A. Yes, it is. The DCF methodology is a market based approach. The price
3 that investors are willing to pay for any particular stock reflects their
4 evaluation of this stock's stream of compensation with that of all other
5 uses to which an investor can direct his funds. Given his income and
6 wealth, the investor will face a set of feasible opportunities at any
7 point in time. These feasible opportunities will include investing in a
8 wide variety of financial assets, real assets, and current consumption.
9 Investors will then allocate their own resources among these feasible
10 opportunities so as to maximize their satisfaction. The net result, in
11 terms of the prices set for these feasible alternatives, will reflect the
12 interactions of the various individuals in the markets. Thus the price of
13 a particular stock reflects the investors' evaluation of its relative
14 attractiveness vis-a-vis all other opportunities. Market results then
15 reflect investors' evaluations of comparable risk opportunities, thus
16 giving information as to what is necessary to attract an investor's funds.

17

18 Q. In implementing the DCF methodology what dividend did you employ?

19 A. The DCF clearly calls for use of the expected dividend yield. An investor
20 purchasing a share of stock today will not be concerned with the level of
21 the past dividend, but with the level of the dividends over the period for
22 which he will hold the stock. Furthermore, since every dividend in the
23 future stream is discounted in the DCF model, the first dividend must be a
24 future dividend, not a current dividend, otherwise it would not be
25 necessary to discount it to find its present value. To arrive at the

1 expected dividend yield one takes the current dividend times the sum of
2 one plus the expected growth rate in dividends per share to calculate the
3 expected dividend. This expected dividend is then divided by the stock
4 price to arrive at the expected dividend yield.

5

6 Q. What stock price did you utilize?

7 A. I calculated the dividend yield using two stock prices, one being the
8 mid-point of the high and low, and the other the arithmetic average of the
9 closing prices, both utilizing the time period of January 1, 1983, to
10 February 28, 1983. These prices represent reasonably current information.

11

12 Q. Why did you use current stock prices rather than prices measured over a
13 longer period of time?

14 A. The DCF technique calls for the use of current stock prices. To use a
15 longer period would be backward rather than forward looking. The DCF
16 model is clearly a forward looking model. Theoretically, if the stock
17 market is efficient, the current price reflects all the information
18 concerning investors' expectations about the future. In fact, investors
19 will utilize all available information including past prices when
20 determining the current price.

21 The relevant dividend yield is the yield that an investor would
22 expect to receive if he invested today, so a current market price must be
23 used to calculate that yield. A spot price should not be used, however,
24 because it may be affected by temporary market aberrations. An average
25 over a relatively short recent period is a good measure of current market

1 price.

2 From a practical point of view, if the stock price has been subject
3 to a great deal of variation over the recent past, taking a slightly
4 longer period may give a better indication of the mean expectations upon
5 which stock prices are based. In the case where a clear trend is evident,
6 shortening the period may better capture the current expectations of
7 investors. In any event, clearly the analyst must use his or her
8 judgement in choosing a period for measuring stock price.

9
10 Q. How did you determine the growth rate in dividends per share?

11 A. Investor's expectations concerning the growth rate in dividends per share
12 is the most difficult element of the DCF model to evaluate. I therefore
13 employed a number of methods to estimate this variable.

14
15 Q. What methods did you use?

16 A. I have utilized the following:

- 17 1. The Value Line forecast growth in dividends per share.
- 18 2. The compound growth rate in dividends per share for 1975-1982.
- 19 3. The average of the annual growth in dividends per share for 1975-1982.
- 20 4. The adjusted Vepco plowback ratio's for 1975-1982.
- 21 5. A least squares estimate of the growth rate in dividends per share
22 over the period 1975-1982.
- 23 6. The overall average historic growth rate.
- 24 7. The average of all growth rates.

25

1 Q. Would you please describe each of these growth rate projections?

2 A. Value Line provides an estimate of the growth in dividends per share for a
3 number of electric utilities. Since the growth rate which we are
4 attempting to estimate is the investor's anticipated growth rate,
5 estimates such as those published by Value Line may well be relied upon.
6 The most recent Value Line Investment Survey for Vepco (Dec. 31, 1982),
7 forecasts a growth rate in dividends per share of 5.0 percent.

8 Taking the approach that lacking perfect knowledge about future
9 events the recent past is the best "hard" indicator of the potential
10 growth in dividends per share, I have computed a number of growth rates
11 using historic information for Vepco over the period 1975-82.

12 Vepco's simple compound growth rate in dividends per share over this
13 period was 3.73%. The average of the yearly growth in dividends per share
14 was 3.75%. This information is given on Schedule 1.

15 A number of analysts utilize a variant of the DCF known as the "br",
16 or plowback variant in order to estimate the growth rate in dividends per
17 share. The derivation of the "br" or plowback variant is given in
18 Appendix C.

19 I have computed the plowback ratio as an estimate of growth over this
20 period. However, an important point needs to be made when using plowback
21 ratios computed over an historical period. When a firm issues new shares
22 of stock at less than book value, the resulting dilution of shares affects
23 retained earnings. That is, the amount of retained earnings is less than
24 it would have been had the dividends per share remained the same and the
25 new shares been issued at book value with no resulting dilution. This is

1 due to the fact that more shares are needed to raise a given amount of new
2 capital when sold at less than book, than when sold at book value. Thus
3 the "br" variant will "build in" this dilution effect when the time period
4 utilized in the analysis is one of continual dilution.

5 Since the "br" term is used to approximate the growth in dividends
6 per share, it too must reflect the expected growth in dividends per
7 share. Thus, by using a period of continual dilution as the basis for our
8 "br" method, we are in effect assuming that investors are expecting
9 continual dilution to occur. If this were true, investors would hardly be
10 interested in purchasing the stock. I have corrected partially for
11 "dilution bias" by adjusting retained earnings under the assumption of no
12 dilution; that is, assuming all new shares had been sold at book value.
13 This adjustment is shown on Schedule 2. The result is a plowback growth
14 estimate of 3.36% when the yearly plowback ratios are averaged over the
15 1975-82 period. It is crucial to keep in mind that this is only a partial
16 correction since if Vepco had experienced no dilution, the impact on
17 earnings may well have been in a positive direction.

18 Finally, I have employed an Ordinary Least Squares (OLS) regression
19 estimate of the growth rate in dividends per share over the period 1975-82.
20 The OLS growth rate is based on the following equation:

$$D_t = D_0 e^{gt}$$

22 where

23 D_t = dividend per share in period t

24 D_0 = dividends per share in the initial period

25 g = continuous compound growth rate

1 t = time

2 e = base for the natural logarithm.

3

4 A least squares regression package can be used to produce an estimate
5 of g . The equation to be estimated is:

$$6 \quad \log D_t = a(\log D_0) + gt$$

7 where log is the natural logarithm.

8 Since a regression package will produce an estimate of both a and g ,
9 the value of a must be restricted to equal one in order to maintain the
10 integrity of the equation.

One advantage of the least squares estimate of growth is that it utilizes all the available data points, as well as the pattern of changes in the data to arrive at an estimate of g .

14

15 Q. Are there any other aspects of the least squares estimate with which we
16 need to be concerned?

17 A. Yes. The growth rate estimate that results from the application of the
18 least squares procedure is a continuous compound growth rate. The other
19 growth rates we have derived are all annual growth rates. Since our
20 concern in these proceedings is to express everything on an annual basis,
21 we must transform the continuous rate to an annual rate before determining
22 the cost of equity. Given a continuous growth rate, g^* , we can transform
23 it to an annual rate g , as follows:

24

25 $q = e^{g^*} - 1.0$

1 The least square regression produced a continuous growth rate of 3.45
2 percent, which when transformed to an annual rate is 3.51 percent.

3
4 Q. You stated that you used the period 1975-1982 as the basis for a number of
5 growth rate estimates. Why did you use this period rather than a longer
6 time period?

7 A. When looking to the past in order to form expectations about the future,
8 the period chosen should, ideally, be free from any particular cyclical
9 dominance, yet should exclude periods which predate major structural
10 changes in the economy. However, it is important that the time period
11 utilized not be purged of "abnormal" periods which are quite likely to
12 persist in the near term. A public utility cannot unilaterally, nor
13 instantaneously, alter its rates or curtail its service in the short run
14 in order to mitigate any adverse temporary market disruptions. However,
15 this does not mean that abnormal events unlikely to persist in the near
16 term should not be adjusted where possible.

17 It is generally agreed that the Oil Embargo of the mid-seventies had
18 a major impact on the energy section of the economy. Following the Oil
19 Embargo of late 1973, the economy fell into a recession in 1974 with real
20 GNP falling by .6% in 1974, and falling by 1.2% in 1975. The CPI rose to
21 11% in 1974 and remained high at 9.1% in 1975. The recession had bottomed
22 out in 1975 with recovery in the second half of the year. Although
23 recovery started in the second half of 1975, the pre-recession 1973 level
24 of real GNP was not reached until 1976. The economy remained relatively
25 healthy over the period 1976-1978 with the rate of inflation as measured

1 by the CPI falling to the 5% - 7% range, and unemployment falling to the
2 6% - 7% range. Real GNP growth had risen to the 5% - 5.5% range.

3 In 1979 inflation had risen to the 11% level. In October 1979, the
4 Federal Reserve shifted its emphasis from interest rates to money & credit
5 expansion to deal with the high levels of inflation, again, driven in part
6 by increases in the price of oil.

7 The period from 1980 to present can be summarized as one of record
8 levels of inflation and interest rates, followed by the nation's deepest
9 post-war recession and record levels of unemployment.

10 In summary, the period 1975 to present represents a period which
11 begins from the trough of a recession, through expansion and a period of
12 moderate health to the extremely volatile period of the last few years.
13 In view of these facts, and the changing emphasis of monetary and fiscal
14 policy, I feel the period 1975 to 1982 represents an appropriate period
15 for analysis.

16

17 Q. Why have you chosen to use a number of different growth rates rather than
18 selecting only one?

19 A. As I stated earlier, the stock price as determined in the market is a
20 result of the interactions of many investors. These investors may run the
21 spectrum from the simple and naive to the ultra-sophisticated. Each will
22 likely employ different methods of evaluating potential investments. Some
23 may calculate simple growth rates, others may go through more complex
24 analysis. For example, with respect to the investor who not only
25 considers the overall growth in dividends over some period of time but

1 also its pattern of change as well, we are more likely to approximate his
2 expectations with the least squares growth rate than with the simple
3 compound growth rate. In any event, the analyst should attempt to infer
4 investors expectations by making reasonable assumptions as to how those
5 expectations may be formed, and utilizing methods of measurement that
6 provide an analytic approximation to the underlying process. The point
7 is, using different measures of growth represents different ways of
8 forming expectations, some may represent expectations formulations
9 directly, some indirectly.

10
11 Q. You have focused on the growth in dividends per share. Why do you feel
12 this is the proper growth rate to utilize?

13 A. Theoretically, an investor should be indifferent between dividends and
14 retained earnings. However, in the context of a regulated utility I feel
15 that investors are primarily concerned with a steady flow of dividends.
16 The nature of regulation is such that the investment opportunities of the
17 regulated utility are not as broad as those of the individual investor.
18 The utility uses its funds to replace old obsolete plant and equipment as
19 well as to expand its productive capacity. The regulated utility under
20 its obligation to serve may well be forced to undertake investments that
21 while necessary to discharge its duties may not be a purely economic
22 decision. Furthermore, unlike the unregulated firm, a regulated utility
23 is not free to enter new markets when opportunities arise.

24 However, this is not to say the investor is not concerned with
25 adequate levels of retained earnings. The retained earnings provide the

1 internal financing of future expansion of assets and hence earnings base
2 on which future dividends rely.

3 In summary, I feel that the investor in a regulated utility prefers a
4 stable dividend growth from his investment to use as a source of funds for
5 other investment opportunities should they arise, or for purposes of
6 current consumption.

7 In view of the above considerations I feel the DCF model presents a
8 good approximation to regulated utilities stock evaluation, and hence an
9 appropriate tool for estimating the cost of capital.

10

11 Q. What range of cost of equity for Vepco do you arrive at using the DCF
12 methodology?

13 A. Schedule 3 shows the derivation of the dividend yields. On Schedule 4, I
14 have listed the growth rate estimates. Finally on Schedules 5 and 6, the
15 dividend yields as well as growth rates are combined to produce a range of
16 "standard" DCF cost of equity of 14.33% to 16.24%, with an average value
17 of 14.9%.

18

19 Q. The "standard" DCF model results you have arrived at suggest a range of
20 cost of equity of 14.33% to 16.24%. Is this then the cost of equity range
21 you would recommend, or are other adjustments and refinements necessary?

22 A. The "standard" DCF model is rather simple in its approximation of investor
23 evaluations. I believe three other items must be taken into account in
24 arriving at a range of cost of equity. These are floatation costs, the
25 timing of actual dividend receipts, and attrition.

-17-

1 When stock is issued the Company does not receive the full market
 2 price of the share. Part of the proceeds go to underwriters to compensate
 3 them for raising the capital. The investor, however, requires a return on
 4 his purchase price. The discrepancy between the price paid by the
 5 investor and the net proceeds to the firm must be recovered by way of an
 6 increase in the return earned, hence allowed. The adjustment which I have
 7 utilized is detailed in the article "Floatation Cost Allowance in Rate of
 8 Return Regulation: A Note" by Enrique R. Arzac and Matityahu Marcus,
 9 Journal of Finance, December 1981.

10 The adjustment takes the form:

$$11 \qquad k^* = k / (1 - (fh / 1 - f))$$

12 where

13 k^* = cost of capital to the company

14 k = market determined cost of capital

15 h = external equity financing rate (new equity as a percent of
 16 earnings)

17 f = floatation costs as a percent of market price.

18 The derivation of the values of h and f are given on Schedule 7 and 8
 19 respectively.

20 Using the results from Schedules 7 and 8 in the formula, we arrive at
 21 a cost of equity range of 14.57% to 16.51%, with an average value of
 22 15.14%, as shown on Schedules 9 and 10.

23 The second point concerning the timing of dividend receipts can be
 24 addressed by utilizing the quarterly version of the DCF model.

25

1 Q. Would you please explain what you mean by the quarterly version of the DCF
2 model?

3 A. The purpose of the quarterly DCF model is to recognize the fact that
4 dividends are paid on a quarterly basis and not simply once a year at the
5 end of the year. The model recognizes that an investor who receives a
6 dividend at the end of the first quarter can reinvest this dividend for
7 the remaining three quarters and generate a return on the reinvested
8 dividends. The quarterly DCF formulation recognizes this
9 payment/reinvestment opportunity explicitly.

10

11 Q. What relevance does the quarterly DCF version have to an investor who does
12 not reinvest his dividends in the stock of the company paying the dividend?

13 A. The model is still appropriate for these investors. If an investor takes
14 cash as opposed to participating in some type of automatic reinvestment
15 plan, there are three possibilities which arise:

- 16 1. The investor reinvests these dividends in the company's stock on his
17 own.
18 2. The investor invests the funds elsewhere.
19 3. The investor uses the funds for purchases of good and services.

20 The first case presents no problem. In the second or third case we
21 must ask ourselves why the investor chose this course of action. If the
22 investor diverts his funds elsewhere, then the risk-adjusted return of
23 investing in the Company's stock as perceived by the investor must be less
24 than the risk adjusted return that can be earned elsewhere. This would
25 imply that the Company is not earning the investor's cost of capital. If

1 the Company were in fact earning the required return (keeping in mind the
2 opportunity cost concept), the investor would be indifferent as to the
3 stock of this particular company and all other investments with equal
4 return on a risk adjusted basis. In fact when the transaction costs are
5 taken into account, a switch in investments would not be willingly made if
6 the Company were earning the investor's required return.

7 The case where the investor uses the dividend proceeds to purchase
8 goods and services is analogous to the above. The difference is that in
9 this case it is the discounted value of consumption of goods and services
10 which provides the investor a greater net present value over the
11 discounted stream of the stock's dividends. This relates directly to the
12 notion that investors must be compensated for deferment of consumption as
13 well as uncertainty and inflation if they are to invest their funds.

14 In all these cases the result is that the investor's required return
15 is an opportunity cost, and the return on common equity must recognize all
16 opportunities faced by the investor if a company is to attract capital.
17 Thus while expressing the required rate of return on an annual basis we
18 can still recognize the quarterly cash disbursements by using this version
19 of the DCF. I have shown the derivation of the quarterly version of the
20 DCF model in Appendix D.

21
22 Q. How did you go about implementing the quarterly DCF model?

23 A. Using Vepco's current quarterly dividend of 40 cents per quarter, I
24 assumed that this dividend will be paid in each of the first three
25 quarters of 1983, and then increase in the fourth quarter of 1983 as is

1 consistent with company policy. Thus at the time of preparing this
2 testimony, an investor would expect to receive 40 cents for two quarters,
3 and the increased dividend for two more quarters if we assume a one year
4 holding period. I then utilized the same two stock prices as I did with
5 the standard DCF model, and the same set of various growth rates.

6 The results of using the quarterly version of the DCF model with no
7 floatation adjustment are shown on Schedules 11 and 12, and indicate a
8 range of cost of equity from 14.73% to 16.63% and an average value of
9 15.3%. The floatation adjusted version is given on Schedules 13 and 14,
10 with a resulting range of 14.97% to 16.9% with an average value of 15.55%.

11

12 Q. You also mentioned the need to consider attrition. Would you please
13 explain what you mean by attrition?

14 A. When speaking of attrition I am referring to the discrepancy between the
15 allowed rate of return on equity and the earned returned on equity. Thus
16 if the allowed return on equity were 17% and the earned return were 16%,
17 we would have attrition of 1%.

18

19 Q. What is the cause of attrition?

20 A. In my view, the primary cause of attrition is the use of a historic test
21 year for rate making purposes. Even after adjustments are made to the
22 test year for known changes and to annualize rates, the fact remains that
23 revenues are set to achieve the allowed rate of return with expenses and
24 plant and equipment valued at test year levels. Given the inevitable fact
25 of inflation, no matter how small, these costs will rise during the period

1 when rates are in effect. This will invariably result in the revenue
2 level being insufficient to generate the allowed return on equity. The
3 time period elapsing from the end of the test year until the new rates go
4 into effect further aggravates the problem.

5
6 Q. How can this attrition problem be overcome?

7 A. In my opinion, the best solution is to use a forecast test period, one
8 which coincides with the period in which the new rates will likely be in
9 effect. Short of this, it must be acknowledged that if Vepco is to have a
10 realistic opportunity to earn the return on equity found reasonable by
11 this Commission, a specific allowance for attrition must be factored into
12 the allowed return on equity.

13
14 Q. Have you examined the attrition experienced by Vepco in the past?

15 A. Yes I have. The calculation I have made is detailed in Appendix E. On
16 Schedule 15 I have shown the derivation of the attrition for Vepco as it
17 pertains to this jurisdiction. On Schedule 15 the weighted return on
18 equity as well as the weighted overall return was derived by weighting the
19 allowed return by the fraction of the year in which rates reflecting these
20 returns were in effect. As can be seen attrition has ranged from .87
21 percent to 3.44 percent over the period 1975-1981.

22 I recognize that Schedule 15 slightly overstates the experienced
23 attrition, because the earned overall return in column (4) does not
24 reflect the usual ratemaking adjustments. Even so, it is clear that
25 substantial attrition has been experienced.

1 Q. How do you suggest that this attrition be remedied in this case?

2 A. Combining the results of the Quarterly DCF Model adjusted for floatation
3 costs as given on Schedules 11 and 12, I arrive at a mean return on equity
4 of 15.55%, with a standard deviation of .58%. Using the mean of 15.55%
5 plus and minus one standard deviation we arrive at a range of 14.97% to
6 16.13% before an allowance for attrition. I would add to this range an
7 attrition allowance at least sufficient to bring the range up to 15.5% to
8 16.5% return on equity. This is a very modest adjustment -- substantially
9 less than shown on Schedule 15 -- but I believe it is an appropriate one
10 in view of the use of unadjusted figures in column (4) of Schedule 15, and
11 in view of the fact that our economy is currently experiencing reduced
12 inflation and reduced inflationary expectations. Clearly, however, some
13 attrition adjustment is called for, and what I have proposed is a very
14 conservation one.

15 My recommendation is based on average values, representing a range of
16 growth estimates of various types of investors. These investors will
17 interact with one another in the market. My use of the average is simply
18 and arithmetic representation of this interaction. By utilizing a range
19 of plus and minus one standard deviation, I am attempting to incorporate a
20 realization of some uncertainty surrounding my average value, reflecting
21 in part the uncertainty over the various growth rates I have employed.

22 Vepco's common stock is currently selling at approximately 80% of
23 book value. Approval of a rate of return on equity at the mid-point of
24 the range I recommend should provide an opportunity for that stock to sell
25 at book value.

1 If the regulatory process is to ensure an efficient allocation of
2 resources to the regulated sector of the economy, then it is necessary
3 that Vepco's stock, as well as that of other regulated companies sell at
4 least at book value. This result is necessary due to the manner in which
5 revenue levels for return are determined, that is, on the basis of net
6 historic cost.

7
8 Q. Would you please summarize your testimony?

9 A. Based on the results of my Quarterly DCF analysis which accounts for the
10 timing of dividend payments, as well as adjusting these basic results for
11 floatation costs and a small attrition adjustment, and recognizing that
12 Vepco stock continues to sell at less than book value, I believe that a
13 range of cost of equity of 15.5% to 16.5% is fair and reasonable for Vepco.

STATEMENT OF BACKGROUND & EXPERIENCE

I received a Bachelor of Business Administration Degree from Kent State University in June 1974. In September of 1974 I entered the PhD program in Economics at Purdue University. I was awarded a Master of Science Degree in Economics from Purdue University in August, 1976. I completed all course work and qualifying examinations for the PhD degree in Economics in May, 1977. While at Purdue I served as a research assistant as well as a graduate instructor in Economics.

I joined the staff of the Forecasting and Economic Analysis department at Vepco in May, 1979, as an Economist. After holding several positions within the department, I was promoted to my present position Director-Economic Analysis, in April, 1982.

I have submitted testimony on cost of equity capital before the Public Service Commission of West Virginia the North Carolina Utilities Commission, the State Corporation Commission of Virginia, and the Federal Energy Regulatory Commission.

I am a member of the American Economic Association, and the National Society of Rate of Return Analysts. I have attended numerous seminars and conferences on rate of return analysis for public utilities.

DERIVATION OF THE DCF EQUATION

An investor in purchasing a share of stock is in effect buying an income stream composed of two parts: 1) the stream of expected dividends that he will receive during the period in which he holds the stock, and 2) the sale price of the stock when he sells it to a future investor. The current price of the stock is equal to the present value of the income stream the investor expects to receive. In order to be compensated for his deferment of consumption, and the uncertainty surrounding the assets' ability to generate income, the investor will require a real return on his investment of, say, r percent per year. The real return is comprised of return required to compensate the investor for deferment of consumption, r^* , and the return required to compensate him for the uncertainty over the income earning ability of the asset, r^{**} . Thus, his real return requirement, r , is given by:

$$r = r^* + r^{**} + r^* r^{**}.$$

This is due to the fact that the discount factor for each year is:

$$(1+r) = \text{discount factor} = (1+r^*)(1+r^{**})$$

$$= 1+r^* r^{**} + r^* r^{**}$$

$$\text{so } r = r^* + r^{**} + r^* r^{**}.$$

Thus, the present value of the income stream is given by:

$$(1) P_0 = (D_1/(1+r)) + (D_2/(1+r)^2) + \dots + (D_n/(1+r)^n) + (P_n/(1+r)^n),$$

assuming the investor disposes of the stock in period n, at a price equal to P_n after receiving the dividend in period n.

An investor purchasing the stock in period n, with a real return requirement of r percent, will set P equal to the present value of his expected income stream. In this case, his first dividend is equal to D_{n+1} . If the second investor holds the stock for m periods, his income stream, discounted at r percent, is:

$$(2) P_n = (D_{n+1}/(1+r)^{n+1}) + (D_{n+2}/(1+r)^{n+2}) + \dots +$$

$$(D_{n+m}/(1+r)^{n+m}) + (P_{n+m}/(1+r)^{n+m})$$

Substituting this into (1) we obtain

$$(3) P_0 = (D_1/(1+r)) + (D_2/(1+r)^2) + \dots +$$

$$(D_{n+m}/(1+r)^{n+m}) + (P_{n+m}/(1+r)^{n+m})$$

Determining the price paid in period $n+m$ in a manner analogous to that of determining the price paid in period n , and continuing this reasoning indefinitely for subsequent investors, we arrive at the following equation for P_0 :

$$(4) P_0 = (D_1/(1+r)) + (D_2/(1+r)^2) + (D_3/(1+r)^3) + \dots$$

Assuming that investors expect the dividends to grow at a constant rate of g percent per year we have :

$$D_1 = D_0(1+g)$$

$$D_2 = D_0(1+g)^2$$

$$D_3 = D_0(1+g)^3$$

where D_0 is the current dividend. Substituting this into equation (4) we have:

$$(5) P_0 = (D_0(1+g)/(1+r)) + (D_0(1+g)^2/(1+r)^2) + (D_0(1+g)^3/(1+r)^3) + \dots$$

It can be shown that if $r > g$, then (5) reduces to:

$$(6) P_0 = (D_0(1+g)/(r-g)) = D_1/(r-g)$$

INFLATION AND THE DCF EQUATION

The derivation of equation (6) was based on the assumption of no inflation. When investors expect inflation, they will pay in current dollars an amount equal to the present value of the deflated (current dollar) income stream. Assuming the investor expects a rate of inflation of i percent per year, the deflated stream of nominal dividends becomes:

$$(7) (D_1/(1+i)) , (D_2/(1+i)^2) , (D_3/(1+i)^3) , \dots$$

Upon substitution of (7) into (5) we obtain

$$(8) P_0 = (D_0(1+g)/(1+r)(1+i)) + (D_0(1+g)^2/((1+r)(1+i))^2) + \dots$$

We note from (8) that the discount factor now becomes :

$$(1+r)(1+i) = 1+r+i+ir, \quad \text{or } 1+k, \quad \text{where } k=r+i+ir$$

We now see that (6) becomes

$$(9) P_0 = D_1/(k-g) \text{ if } k > g, \quad \text{where } k = r+i+ir.$$

From equation (9) we can solve for k to give:

$$(10) k = (D_1/P_0) + g$$

which is the well known DCF equation for the cost of capital. We note that this implies

$$(11) \quad r + i + ir = (D_1/P_0) + g .$$

That is, the compensation for deferment of consumption and the uncertainty over the asset's ability to earn income, plus the compensation for inflation equals the expected dividend yield plus the expected growth rate in dividends per share.

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ATTACHMENT B
PAGE 1 of 2DERIVATION OF THE "BR" VARIANT OF THE DCF

As shown in Attachment A, the general form of the DCF equation is:

$$k = (D_1/P_0) + g$$

where k = investor's required return,

D_1 = dividend per share, --expected,

P_0 = current market price per share,

g = expected rate of growth in dividends per share.

We note that earnings per share E_t , is given by the product of the earned rate of return, r , and the book value at the beginning of the year B_{t-1} . Assuming $r = k$, i.e., the company earns the required return (ignoring flotation costs since we are focusing on the investor's required return) we have :

$$E_t = rB_{t-1}$$

Dividends per share, D_t , are equal to earnings per share minus retained

107

earnings per share R_t . Retained earnings per share are equal to earnings per share times the retention rate, b . Thus,

$$R_t = bE_t$$

$$D_t = E_t - R_t = rB_{t-1} - bE_t$$

$$D_t = rB_{t-1} - brB_{t-1} = rB_{t-1}(1-b)$$

$$D_t = rB_{t-1}(1-b)$$

Analogously, dividends per share in period $t+1$ are equal to :

$$D_{t+1} = rB_t(1-b)$$

The growth rate in dividends is given by :

$$(D_{t+1} - D_t) / D_t = (rB_t(1-b) - rB_{t-1}(1-b)) / (rB_{t-1}(1-b))$$

$$= ((1-b)r(B_t - B_{t-1})) / (r(1-b)B_{t-1})$$

$$= ((1-b)r(B_{t-1} + R_t - B_{t-1})) / ((1-b)rB_{t-1})$$

$$= R_t / B_{t-1}$$

Thus, the expected growth rate in dividends per share is given by the ratio of retained earnings during the year to book value at the beginning of the year.

DERIVATION OF THE QUARTERLY DCF MODEL

We assume that dividends are paid at the end of each quarter, and that the dividend increase will occur in the last quarter of the holding period. It is assumed that the investor utilizes the quarterly dividends in whatever manner he chooses such that the effective return on the use equals his opportunity cost, k . The opportunity cost is measured as an annual rate of return. The investor is assumed to have a one year evaluation period.

Let

$d_t(q)$ = the dividend in quarter q of year t

k = the investor's required rate of return

P = the current stock price

D_t = the annual cash dividend in year t

$$D_t = d_t(1) + d_t(2) + d_t(3) + d_t(4)$$

g = the growth rate in annual dividends

z = the growth rate in dividends from the third
to the fourth quarter

The annual dividend in year one is given by:

$$D_1 = d_1(1) + d_1(2) + d_1(3) + d_1(4).$$

Our assumption that dividends are constant for the first three quarters implies:

$$d_t(1) = d_t(2) = d_t(3),$$

so

$$d_1(1) = d_1(2) = d_1(3),$$

therefore

$$d_1(1) + d_1(2) + d_1(3) = 3d_1(1)$$

or in general

$$d_t(1) + d_t(2) + d_t(3) = 3d_t(1).$$

With dividend growth occurring in the fourth quarter at a rate z over the third quarter we have:

$$d_t(4) = (1+z)d_t(3)$$

so

$$d_1(4) = (1+z)d_1(3)$$

$$d_1(4) = (1+z)d_1(1)$$

since

$$d_1(3) = d_1(1).$$

Thus the annual dividend in period 1 is:

$$D_1 = 3d_1(1) + (1+z)d_1(1) = d_1(1)(3+(1+z)).$$

110

The annual dividend in period two is given by:

$$D_2 = d_2(1) + d_2(2) + d_2(3) + d_2(4);$$

which by our assumptions about dividend growth implies

$$D_2 = 3d_2(1) + (1+z)d_2(1).$$

We note that with dividend growth occurring only once a year we have:

$$d_2(1) = d_1(4)$$

and

$$d_2(1) = (1+z)d_1(1)$$

which means

$$D_2 = 3(1+z)d_1(1) + (1+z)^2d_1(1)$$

and

$$D_2 = (1+z)d_1(1)(3 + (1+z))$$

Thus, given the growth rate in annual dividends of g , we have

$$(D_2 / D_1) = (1 + g).$$

Substituting for D_2 and D_1 we obtain:

$$(1+g) = (D_2/D_1) = ((1+z)d_1(1)(3+(1+z)))/(d_1(1)(3+(1+z))) = (1+z)$$

and therefore, $g = z$.

Therefore, in the quarterly DCF model the third to fourth quarter growth rate is equal to the annual growth rate in this case.

Given the investor's required rate of return k , each quarterly dividend for the quarters one through three will be utilized to realize a return equal to k on an annual basis. That is, the first quarter dividend will earn at a rate (implicit or explicit) of k for three fourths of a year, the second quarter dividend for one-half year, the third quarter dividend for one-fourth year, and the fourth quarter dividend will not be reinvested so as to evaluate the annual return.

Thus, the effective present value of the first annual dividend is:

$$(D_1/(1+k)) =$$

$$(d_1(1)((1+k)^{3/4} + d_1(2)(1+k)^{1/2} + d_1(3)(1+k)^{1/4} + (1+g)d_1(4)))/(1+k)$$

Upon utilizing our previous results this simplifies to:

$$(D_1/(1+k)) = (d_1(1)((1+k)^{3/4} + (1+k)^{1/2} + (1+k)^{1/4} + (1+g))) / (1+k)$$

The discounted value of the second annual dividend is $(D_2/(1+k)^2)$

$$= (d_2(1)(1+k)^{3/4} + d_2(2)(1+k)^{1/2} + d_2(3)(1+k)^{1/4} + (1+g)d_2(4)) / (1+k)^2$$

$$= (d_1(1)(1+g)((1+k)^{3/4} + (1+k)^{1/2} + (1+k)^{1/4} + (1+g))) / (1+k)^2$$

$$= (1+g)D_1 / (1+k)^2$$

Therefore, the present value of the perpetual stream reduces to

$$P = \sum (D_t / (1+k)^t)$$

$$= \sum (D_1(1+g)^t / (1+k)^t)$$

which when $k > g$ reduces to the familiar

$$P = D_1 / (k-g)$$

or

$$P = (d_1(1)((1+k)^{3/4} + (1+k)^{1/2} + (1+k)^{1/4} + (1+g))) / (k-g)$$

The value of k , the required rate of return, can be solved for through the use of a non-linear iterative procedure.

The basic results obtained above hold when the dividend increase occurs earlier than the fourth quarter. For example, if the dividend increase is expected to occur in the third quarter of the holding period the expression becomes:

$$P = (d_1(1)((1+k)^{3/4} + (1+k)^{1/2} + (1+g)(1+k)^{1/4} + (1+g))) / (k-g)$$

The growth rate g , remains equal to the annual growth rate regardless of when the dividend increase occurs.

CALCULATION OF ATTRITION

For our purposes we shall define attrition as the difference between the allowed return on equity and the earned return on equity.

The overall rate of return shall be defined as the weighted average of the rate of return on equity times the capitalization rate on equity plus the sum of the allowed rate of return on all other items times their capitalization rates. We shall express the latter elements in one generic term denoted "other". The "other" category includes all fixed obligations.

Symbolically:

$$(1) \quad ROR = e(ROE) + d(D)$$

where

ROR = allowed overall rate of return

e = capitalization rate on equity

d = capitalization rate on "other"

D = embedded cost of "other"

ROE = allowed return on equity

Given ROR, e and ROE we can solve for d(D), the allowed weighted rate of return on other as:

$$(2) \quad d(D) = ROR - e(ROE).$$

111

If we let the actual (as opposed to the allowed) rate of return carry the subscript ,a, we have

$$(3) \quad ROR_a = e(ROE_a) - d(D_a)$$

Since the earned return on equity is the residual after all fixed obligations are met, and assuming that all fixed obligations have been met, we set

$$(4) \quad d(D_a) = d(D), \quad \text{thus}$$

$$(5) \quad ROR_a = e(ROE_a) - d(D)$$

which implies

$$(6) \quad ROE_a = (ROR_a - d(D)) / e$$

Nominal attrition is then defined as:

$$(7) \quad \text{ATTRITION} = ROE - ROE_a.$$

Virginia Electric & Power Company

Vepco Dividends Per Share
1975-1982

<u>Year</u>	<u>Dividend</u>	<u>Percent Change</u>
1975	1.18	.
1976	1.225	3.81
1977	1.24	1.22
1978	1.30	4.84
1979	1.38	6.15
1980	1.40	1.45
1981	1.425	1.79
1982	1.525	7.02

Average percent change 1975-1982 3.75

Compound growth rate 1975-1982 3.73

Source: Virginia Electric Power Company

Adjustment for Dilution
1975-1982

(1) Year	(2) Common Shrs Begin of Year (000)	(3) Book Value per Share Beginning of Year (000)	(4) Amount Received on New Common Stock Issues (000)	(5) New Shares (Adjusted) (4)/(3) (000)	(6) Total Shares End of Year (Adjusted) (2) + (5) (000)	(7) Retained Earnings Beginning of Year (000)	(8) Net Income (000)	(9) Preferred & Preference Stock Dividends (000)	(10) Dividends per Shr Common Stock
1975	57,777 *	18.05 *	121,087 *	6708	64,485	242,742 *	154,732 *	35,971 *	1.18 *
1976	64,485	18.71	85,502 *	4570	69,055	285,411	166,786 *	43,821 *	1.225 *
1977	69,055	19.26	83,842 *	4353	73,408	323,784	189,793 *	47,719 *	1.24 *
1978	73,408	19.96	84,739 *	4245	77,653	374,832	203,864 *	53,588 *	1.30 *
1979	77,653	20.60	84,198 *	4087	81,740	424,159	196,467 *	55,046 *	1.38 *
1980	81,740	20.95	76,590 *	3656	85,396	452,779	241,620 *	57,290 *	1.40 *
1981	85,396	21.70	48,652 *	2242	87,638	517,555	237,780 *	57,710 *	1.425 *
1982	87,638	22.33	132,442 *	5931	93,569	572,741	278,589 *	56,991 *	1.525 *

(11) Year	(12) Tot Com Div (Adjusted) (10) x (6) (000)	(13) Retained Earnings (Adjusted) (8) - (9) - (11) (000)	(14) Retained Earnings End of Yr (Adjusted) (7) + (12) (000)	(15) Common Stock Beginning of Year (000)	(16) Common Stock End of Yr (Adjusted) (14) + (4) (000)	(17) Com Eq Plus Ret Earn (Adjusted) (15) + (13) (000)	(18) Book Value Per Share End of Yr (Adjusted) (16)/(6) (000)	(19) Book Value Beginning of Year (2) x (3) (000)	(20) Growth Rate (12)/(18)
1975	76,092	42,669	285,411	799,935 *	921,022	1,206,433	18.71	1,042,875 *	4.09%
1976	84,592	38,373	323,784	921,022	1,006,524	1,330,308	19.26	1,206,514	3.18%
1977	91,026	51,048	374,832	1,006,524	1,090,366	1,465,198	19.96	1,329,999	3.84%
1978	100,949	49,327	424,159	1,090,366	1,175,105	1,599,264	20.60	1,465,224	3.37%
1979	112,801	28,620	452,779	1,175,105	1,259,303	1,712,082	20.95	1,599,652	1.79%
1980	119,554	64,776	517,555	1,259,303	1,335,893	1,853,448	21.70	1,712,453	3.78%
1981	124,884	55,186	572,741	1,335,893	1,384,545	1,957,286	22.33	1,853,093	2.98%
1982	142,693	78,905	651,646	1,384,545	1,516,987	2,168,633	23.18	1,956,957	4.03%

* Denotes Actual Value

Average
1975-82 3.38%

Source:
Virginia Electric and Power Company

VIRGINIA ELECTRIC & POWER COMPANY
COMMON STOCK PRICE

YEAR	MONTH	DAY	HIGH	LOW	CLOSE
83	1	3	14.625	14.375	14.625
83	1	4	14.625	14.250	14.625
83	1	5	14.875	14.625	14.625
83	1	6	14.875	14.500	14.625
83	1	7	15.000	14.625	15.000
83	1	10	15.000	14.625	14.875
83	1	11	15.125	14.750	15.000
83	1	12	15.000	14.750	15.000
83	1	13	15.000	14.750	15.000
83	1	14	15.000	14.750	15.000
83	1	17	15.000	14.750	15.000
83	1	18	15.000	14.875	15.000
83	1	19	15.250	15.000	15.125
83	1	20	15.125	15.000	15.125
83	1	21	15.125	15.000	15.125
83	1	24	15.000	14.750	14.875
83	1	25	15.125	14.875	15.000
83	1	26	15.125	14.875	15.000
83	1	27	15.250	14.875	15.250
83	1	28	15.250	15.000	15.250
83	1	31	15.250	14.875	15.000
83	2	1	15.250	15.000	15.125
83	2	2	15.250	15.000	15.250
83	2	3	15.250	15.125	15.125
83	2	4	15.250	15.125	15.250
83	2	7	15.500	15.125	15.500
83	2	8	15.500	15.250	15.250
83	2	9	15.375	15.250	15.375
83	2	10	15.375	15.125	15.375
83	2	11	15.625	15.250	15.375
83	2	14	15.375	15.125	15.375
83	2	15	15.500	15.250	15.375
83	2	16	15.375	15.125	15.125
83	2	17	15.250	15.000	15.250
83	2	18	15.375	15.125	15.250
83	2	22	15.375	15.125	15.250
83	2	23	15.000	14.625	14.750
83	2	24	15.000	14.750	14.875
83	2	25	15.000	14.625	14.875
83	2	28	14.875	14.625	14.875

High = 15.625

Low = 14.250

$$\frac{\text{High} + \text{Low}}{2} = 14.94$$

Average Close = 15.07

Current Yield

$$\text{Based on Avg. of High \& Low} = \frac{1.60}{14.94} = .1071$$

$$\text{Based on Avg. Close} = \frac{1.60}{15.07} = .1062$$

Estimated Growth Rates

<u>Estimate</u>	<u>Value</u>
Value Line Forecast	5.00%
Compound Growth (75-82)	3.73%
Annual Average Growth (75-82)	3.75%
Least Squares on Annual Basis(75-82)	3.51%
Adjusted Plowback(75-82)	<u>3.38%</u>
Average of Historic Growth Rates	3.59%
Overall Average	3.87%

VEPCO-JPC
Schedule 5

Standard DCF Model
Price is Average of Daily Closing Price For The Period
No Flotation Adjustment

<u>Growth Rate</u>	<u>Current Yield</u>	<u>Expected Yield</u>	<u>K</u>
Value Line Forecast	10.62	11.15	16.15
Compound (75-82)	10.62	11.02	14.75
Annual Average (75-82)	10.62	11.02	14.77
Least Squares (75-82)	10.62	10.99	14.50*
Adjusted Plowback (75-82)	10.62	10.98	14.36
Average All Historic	10.62	11.00	14.59
Overall Average	10.62	11.03	14.90

Variable	Mean	Standard Deviation	Minimum Value	Maximum Value
K	14.86	0.60	14.36	16.15

Standard DCF Model
Price is Average of High and Low For The Period
No Flotation Adjustment

<u>Growth Rate</u>	<u>Current Yield</u>	<u>Expected Yield</u>	<u>K</u>
Value Line Forecast	10.71	11.25	16.25
Compound (75-82)	10.71	11.11	14.84
Annual Average (75-82)	10.71	11.11	14.86
Least Squares (75-82)	10.71	11.09	14.60
Adjusted Plowback (75-82)	10.71	11.07	14.45
Average All Historic	10.71	11.09	14.68
Overall Average	10.71	11.12	14.99

Variable	Mean	Standard Deviation	Minimum Value	Maximum Value
K	14.95	0.60	14.45	16.25

Derivation of Equity Financing Rate

<u>Year</u>	Proceeds from public offering (000)	Previous year net income (000)	h (2)-(3)
1975	113980	127162	.90
1976	73875	154732	.48
1977	70400	166786	.42
1978	68275	189793	.36
1979	64050	203864	.31
1980	53950	196467	.27
1981	22290	241620	.09
1982	132442	237780	.56
Average 1975-1982			.42

Source: Virginia Electric & Power Company

Flotation Costs as a Percentage of Market Price

(New Issues)

<u>Year</u>	<u>percent</u>
1975	4.75
1975	4.15
1976	3.11
1977	3.23
1978	3.33
1979	4.04
1980	4.09
1982	3.88
1982	<u>3.16</u>
 Average 1975-1982	 3.75

Source: Virginia Electric & Power Company

Standard DCF Model
Price is Average of Daily Closing Price For The Period
Flotation Adjusted (A & M)

<u>Growth Rate</u>	<u>K</u>	<u>K*</u>
Value Line Forecast	16.15	16.42
Compound (75-82)	14.75	14.99
Annual Average (75-82)	14.77	15.02
Least Squares (75-82)	14.50	14.74
Adjusted Plowback (75-82)	14.36	14.60
Average All Historic	14.59	14.83
Overall Average	14.90	15.15

Variable	Mean	Standard Deviation	Minimum Value	Maximum Value
K	15.11	0.61	14.60	16.42

Standard DCF Model
Price is Average of High And Low For The Period
Flotation Adjusted (A & M)

<u>Growth Rate</u>	<u>K</u>	<u>K*</u>
Value Line Forecast	16.25	16.52
Compound (75-82)	14.84	15.09
Annual Average (75-82)	14.86	15.11
Least Squares (75-82)	14.60	14.84
Adjusted Plowback (75-82)	14.45	14.69
Average All Historic	14.68	14.92
Overall Average	14.99	15.24

Variable	Mean	Standard Deviation	Minimum Value	Maximum Value
K	15.20	0.61	14.69	16.52

Quarterly DCF Model
Price is Average of High And Low For The Period
No Flotation Adjustment

<u>Growth Rate</u>	<u>K</u>
Value Line Forecast	16.63
Compound (75-82)	15.24
Annual Average (75-82)	15.26
Least Squares (75-82)	15.00
Adjusted Plowback (75-82)	14.83
Average All Historic	15.08
Overall Average	15.39

Variable	Mean	Standard Deviation	Minimum Value	Maximum Value
K	15.35	0.60	14.83	16.63

Quarterly DCF Model
Price is Average of Daily Closing Price For The Period
No Flotation Adjustment

<u>Growth Rate</u>	<u>K</u>
Value Line Forecast	16.52
Compound (75-82)	15.13
Annual Average (75-82)	15.16
Least Squares (75-82)	14.89
Adjusted Plowback (75-82)	14.73
Average All Historic	14.98
Overall Average	15.29

Variable	Mean	Standard Deviation	Minimum Value	Maximum Value
K	15.24	0.59	14.73	16.52

Quarterly DCF Model
Price is Average of High And Low For The Period
Flotation Adjustment (A&M)

<u>Growth Rate</u>	<u>K</u>
Value Line Forecast	16.90
Compound (75-82)	15.49
Annual Average (75-82)	15.51
Least Squares (75-82)	15.24
Adjusted Plowback (75-82)	15.08
Average All Historic	15.33
Overall Average	15.65

Variable	Mean	Standard Deviation	Minimum Value	Maximum Value
K	15.60	0.60	15.08	16.90

Quarterly DCF Model
Price is Average of Daily Closing Price For The Period
Flotation Adjustment (A&M)

<u>Growth Rate</u>	<u>K</u>
Value Line Forecast	16.80
Compound (75-82)	15.38
Annual Average (75-82)	15.41
Least Squares (75-82)	15.14
Adjusted Plowback (75-82)	14.97
Average All Historic	15.23
Overall Average	15.54

Variable	Mean	Standard Deviation	Minimum Value	Maximum Value
K	15.50	0.61	14.97	16.80

**Calculation of Attrition
Virginia Jurisdiction**

(1) Year	(2) Weighted Allowed Return on Equity	(3) Weighted Allowed Overall R O R	(4) Earned Overall Return (per book)	(5) Overall Attrition (3) - (4)	(6) Equity Capitalization Rate
1975	13.13	9.00	8.69	0.31	.35
1976	13.50	9.60	8.46	1.14	.34
1977	13.50	9.60	8.83	0.77	.34
1978	13.50	9.60	8.62	0.98	.34
1979	13.50	9.60	8.43	1.17	.34
1980	13.50	9.65	8.97	0.68	.34
1981	14.00	10.09	9.17	0.92	.33

(7) Equity Component (2)x(6)	(8) Embedded Fixed Cost Component (3)-(7)	(9) Available to Equity (4)-(8)	(10) Earned Return on Equity (9)/(6)	(11) Equity Attrition (2)-(10)
1975	4.60	4.40	4.29	12.26
1976	4.59	5.01	3.45	10.15
1977	4.59	5.01	3.82	11.24
1978	4.59	5.01	3.61	10.62
1979	4.59	5.01	3.42	10.06
1980	4.59	5.06	3.91	11.50
1981	4.62	5.47	3.70	11.21

Source:
Virginia Electric and Power Company

123

TESTIMONY OF EUGENE W. MEYER
FOR
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE 830029

1 Q. Please state your name, occupation and business address.

2 A. My name is Eugene W. Meyer. I am a Vice President and Director of
3 Kidder, Peabody & Co. Incorporated, 10 Hanover Square, New York,
4 New York.

5 Q. Please describe your business background in the investment banking and
6 securities brokerage business.

7 A. I am Director of the Utility Corporate Finance Department of Kidder,
8 Peabody & Co. Incorporated. I am engaged primarily with raising new
9 capital for the electric, gas and telephone industries. My duties entail
10 intensive research, assistance and guidance in negotiated public offer-
11 ings, direct placements of utility securities and competitive bidding. I
12 am responsible for price negotiations in all utility offerings where
13 Kidder, Peabody is chosen to manage or co-manage the transaction.

14 Appendix A summarizes my educational and business background.

15 Q. Are you familiar with the application currently before the State
16 Corporation Commission of Virginia (the Virginia Commission) wherein
17 Virginia Electric and Power Company (the Company or VEPCO) has re-
18 quested authority to increase and adjust certain rates and charges?

1 A. Yes, I am.

2 Q. What is the subject of your testimony in these proceedings?

3 A. The purpose of my testimony is to describe investor requirements,
4 generally, and to evaluate Virginia Electric and Power Company's
5 current financial position and its prospective financial condition. My
6 testimony will test to see if the Company's requested 16.0% return on
7 equity is adequate under current market conditions. I will also describe
8 current market conditions for new long-term senior securities and
9 common stock.

10 The purpose of discussing capital markets in my testimony is to
11 describe the arena where the Company's management must take the
12 results of the decision in this proceeding when new capital is needed to
13 provide future services. The point is that the free market will deter-
14 mine the cost of capital to this company, other companies, municipal-
15 ities, the state governments and, the Federal Government. Such deter-
16 mination will depend on a whole host of political and economic
17 evaluations which are melded together to produce a price for capital.

18 The matter of anticipated inflation has an important negative im-
19 pact on American life today. Thus, in my testimony, I will endeavor to
20 show the Commission the impact of anticipated inflation upon the cost
21 of capital.

22 Q. Mr. Meyer, were the Schedules submitted by you in this matter
23 prepared by you or under your direction?

24 A. Yes.

25

FINANCIAL HISTORY

1 Q. Would you please review and evaluate the financial history and results
2 of Virginia Electric and Power Company?

3 A. In Schedule I, I have presented financial results for the Company which
4 are generally used by financial analysts. These results have been
5 presented for the ten-year period ending 1982.

6 The schedule shows that the Company's operating revenues have
7 increased at a 17.6% annual rate. The non-cash (AFUDC) credit has
8 increased at an annual rate of 5.4% since 1972 and in 1982 represented
9 38% of Income Applicable to Common. During the entire 1972 - 1982
10 period, earnings per share excluding the non-cash AFUDC credit were
11 below the Company's cash dividend.

12 Since 1972, interest charges and preferred dividend costs increas-
13 ed at annual rates of 15.7% and 12.1%, respectively. The increases in
14 the preferred dividend cost and interest charges were the result of
15 higher costs of new capital and rising construction expenditures.

16 Earnings for common equity increased at the lesser annual rate of
17 9.5%. However, because of the need to sell new common equity to
18 support the construction program, earnings per share decreased at a
19 least square annual rate of 0.7% since 1972. It should be noted that
20 during this period, when earnings per share decreased at an annual rate
21 of 0.7% and dividends increased at an annual rate of only 3.0%, the
22 annual increase in the consumer price index was 8.8%.

1 The Company's common shareholders have fared poorly in recent
2 years. The average market value of the Company's common stock
3 decreased from \$20.438 in 1972 to \$11.063 per share in 1975^{1/2} and then
4 increased to \$15.063 in 1977. The 1982 average market value was
5 \$13.125 and the annual rate of decrease in market value since 1972 was
6 3.5%.

THE BOND MARKET

1 Q. Would you please discuss current utility long-term bond market condi-
2 tions?

3 A. Bond market conditions since October of 1979 have been the worst I
4 have ever witnessed in my career. The previous most difficult period
5 was that of 1974-1975.

6 As may be seen on page one of Schedule 2, Aa rated outstanding
7 utility bond interest rates rose to then exceptionally high levels during
8 1974 and 1975. For instance, Aa rated outstanding utility bonds
9 averaged 8.15% in January of 1974, increased consistently to a then
10 peak level of 10.05% in September of 1974 and remained at levels above
11 9% throughout 1975.

12 In the case of A rated utility bonds, page one of Schedule 2 shows
13 there was an increase for A bonds from a low of 8.36% in January, 1974
14 to a high of 10.78% in October 1974, remaining at levels above 10%
15 throughout 1975, with the exceptions of February and March.

16 Since Chairman Volcker of the Federal Reserve announced a tight
17 money policy in early October, 1979, bond interest rates have worked
18 substantially higher than those high levels achieved in 1974-1975.
19 Pages two, three and four of Schedule 2 indicate the trend.
20 Outstanding Aa rated utility bonds averaged 9.94% in September of
21 1979 and increased steadily to a level of 14.09% in March, 1980. The
22 monthly average for Aa rated bonds then trended downward to 11.73%

1 in June, 1980 before increasing to a high of 16.58% as of September,
2 1981. The Aa rated average for utility bonds during February, 1983 was
3 13.02%.

4 The rates for A rated utility bonds also skyrocketed since
5 Volcker's announcement. Again, as pages two, three and four of
6 Schedule 2 indicate, the interest rate for A rated utility bonds in Sep-
7 tember of 1979 was 10.36%. This increased to 14.65% in March, 1980,
8 declined to 12.21% in June and then increased to 17.21% in October,
9 1981. The A rated utility bonds averaged 14.26% as of February, 1983.

10 Q. You stated earlier that prior to the present period, the bond market's
11 most difficult period, as evidenced by high interest rates, was in 1974-
12 1975. What caused the rise in interest rates in that period?

13 A. In my judgment, the principal factor accounting for the increase in
14 long-term interest rates in the period up to 1975 was a rise in the
15 expected rate of inflation.

16 To explain further, long-term interest rates include a portion for
17 the use of money, a portion to offset the loss of purchasing power due
18 to inflation and a portion to offset the higher risk of companies with
19 lower bond ratings.

20 It can be assumed that the charge for the use of money remains
21 unchanged over time in the range of 2.5% - 3.0%. Thus, the average
22 interest rate of Aa rated utility bonds and A rated utility bonds in both
23 1965 and 1975 would include about 2.75% for the use of money. The
24 remainder of the interest rate is required to offset inflation and allow
25 for a credit risk differential as shown in the following table:

	1965			1975		
	U.S. Bonds	Aa	A	U.S. Bonds	Aa	A
	4.27%	4.52%	4.58%	8.19%	9.44%	10.09%
Less: Use of Money	2.75	2.75	2.75	2.75	2.75	2.75
Remainder	1.52%	1.77%	1.83%	5.44%	6.69%	7.34%
Less:						
Anticipated Inflation Rate	1.52	1.52	1.52	5.44	5.44	5.44
Credit Risk	0%	.25%	.31%	0%	1.25%	1.90%

Since long-term U.S. Government debt obligations are perceived to have little or no credit risk, the difference between the actual interest rate on such obligations and the 2.75% charge for the use of money is considered to be the inflation rate which investors expect over the long term. For instance, in the above table that rate was 1.52% in 1965 and 5.44% in 1975.

To find the portion of the interest rate attributable to the credit risk differential for Aa rated and A rated utility bonds, we must deduct the 2.75% portion for the use of money and the perceived inflation rate from the total interest rate. In the table, it may be seen that investors in 1965 required only 25 basis points and 31 basis points more interest for Aa rated and A rated utility bonds, respectively, to offset the credit difference vs. U.S. Government Bonds. For the credit risk differential vs. U.S. Government Bonds by 1975, however, investors indicated a greatly increased credit risk for the utility industry by requiring a differential of 125 basis points for Aa rated utility bonds and 190 basis points for A rated utility bonds.

As the economy's inflation rate declined after 1975, investors apparently slightly lowered their long-term inflation rate expectations and, thus, required less compensation for the inflation risk. In addition,

1 the rate relief finally granted to utilities resulted in somewhat lower
2 credit risk than that which obtained in 1975. Thus, interest rates
3 trended downward until the end of 1977 when the trend began to move
4 upward.

5 Q. What is the cause of the upward trend in interest rates since 1977?

6 A. In my judgment, the primary reason is the huge budget deficits incurred
7 by the Federal Government and the resultant high inflation rates which
8 have occurred in recent years. Investors fear that these trends will
9 continue. They realize that long-term commitments in debt securities
10 are subjected to an ongoing decline in the purchasing value of the
11 dollars invested. The Federal Reserve Board is also aware that one of
12 the ways to try to curb the rate of inflation is through restrictive
13 monetary policy. Thus, the Fed began pursuing a restrictive monetary
14 policy in the early Fall, 1979. An analysis of 1982 and February, 1983
15 interest rates follows:

	1982			February, 1983		
	<u>U.S. Bonds</u>	<u>Aa</u>	<u>A</u>	<u>U.S. Bonds</u>	<u>Aa</u>	<u>A</u>
18	12.92%	14.79%	15.86%	11.03%	13.02%	14.26%
19 Less: Use of Money	<u>2.75</u>	<u>2.75</u>	<u>2.75</u>	<u>2.75</u>	<u>2.75</u>	<u>2.75</u>
20 Remainder	10.17%	12.04%	13.11%	8.28%	10.27%	11.51%
21 Less:						
22 Anticipated Inflation Rate	<u>10.17</u>	<u>10.17</u>	<u>10.17</u>	<u>8.28</u>	<u>8.28</u>	<u>8.28</u>
23 Credit Risk Diff.	0%	1.87%	2.94%	0%	1.99%	3.23%

24 The 1982 figures indicate that investors were even more fearful of the
25 effects of inflation on their investment than in 1975. In 1982, the
26 perceived long-term inflation rate increased to 10.17% from 5.44% in
27 1975. In addition, the credit risk differential in 1982 even exceeded the
28 levels of 1975.

1 Furthermore, as of February, 1983, the long-term inflation rate
2 perceived by investors was 8.28% and the credit risk was 1.99% for Aa
3 bonds and 3.23% for A bonds. It is obvious that interest rates for utility
4 bonds remain at very high levels, even if not at peak levels. In my
5 judgment, two factors account for this high level — the continued
6 expectation of a high rate of inflation and deteriorating credit condi-
7 tions in the utility industry.

8 Q. What has been the impact of the sharply higher interest rates upon bond
9 investors?

10 A. Bond investors have recorded paper losses in their bond portfolios, and,
11 in some cases, realized actual losses when bonds had to be sold from
12 portfolios for reasons of law, performance or fiduciary responsibility.
13 Both the rising inflation rate and the increasing credit risk differential
14 have been responsible for declining bond prices. Pension funds especi-
15 ally have been vulnerable since the advent of ERISA (Employee
16 Retirement Income Security Act of 1974) which required the funds to
17 mark their bond portfolios to market. In periods of high interest rates,
18 such markings can leave a pension fund in such a position that
19 additional fundings are required by the sponsoring organization so that
20 ERISA's funding requirements can be met.

21 As a result, bond investors have been loathe to invest in conven-
22 tional long-term utility first mortgage bonds with five-year call protec-
23 tion and minimal to no sinking funds. Shorter maturities from seven to
24 ten years became the rule rather than the exception. In some
25 instances, cash sinking funds were required and call protection

1 was extended.

2 Similarly, institutional preferred stock investors have turned away
3 from perpetual preferred stock offerings. Such issues used to be
4 marketable in size with only five year call protection and no sinking
5 fund. Today, cash sinking funds or variable dividend rates have been
6 required to sell preferred stock to professional preferred stock inves-
7 tors.

8 The constant downgrading of utility bonds and preferred stocks
9 over the past decade has further compounded fixed-income investors'
10 problems. Schedule 3 indicates the bond rating reductions that have
11 occurred in the utility industry since 1970 including, unfortunately,
12 Virginia Electric and Power Company.

13 Q. What do higher interest rates and lower bond ratings mean to utility
14 companies?

15 A. Obviously, the cost of money increases sharply. The wider the
16 differential between the cost of new debt and the embedded cost of
17 debt, the more rapidly the embedded cost increases as new debt is
18 added to the capitalization. Further, the more rapid the increase in the
19 embedded cost, the greater is the downward pressure on coverage
20 ratios. The only two defenses available to a company against the
21 pressure of declining coverage ratios are: (1) increase the earnings by
22 whatever means are available, and (2) reduce the debt ratio in the
23 capital structure.

24 The first defense, of course, is affected by controlling costs and
25 increasing revenues. The second defense is accomplished by increasing

1 the equity ratio. When perpetual preferred stock was available, it
2 served as an aid in increasing the equity ratio. Now that cash sinking
3 funds are often required to market preferred stock, it is, at the very
4 least, questionable whether such capital is equity. In fact, the SEC
5 requires that companies show perpetual preferred stock and sinking
6 fund preferred stock separately in the capitalization section of the
7 registration statement.

8 The shorter maturities required to market new bonds today mean
9 that utilities are financing for 10 years, or less, plant which they are
10 depreciating over 30 years, thus increasing the financial risk to the
11 common stockholders. The cost of capital increases as the risks to the
12 common stockholders increases.

13 Finally, if a utility is downgraded because of inadequate coverage
14 ratios and too much leverage in the capital structure, the company's
15 access to new capital is threatened. This is especially true during
16 difficult markets. During such markets, lower rated companies are
17 often unable to find purchasers for new debt in the amount necessary to
18 finance construction needs. At times, even Aa and A rated companies
19 have difficulty obtaining long-term capital. Often other inducements,
20 mentioned before, which are less favorable to the company, are
21 required to accomplish debt financings. Such requirements as shorter
22 maturities, cash sinking funds and longer call protection are required in
23 addition to the much higher interest rate differential between rating
24 categories. The cost of distribution is also higher for lower rated
25 companies because the size of the market is smaller. Finally, the cost

1 of equity capital is also higher for lower rated companies due to the
2 greater financial risk taken by the common stockholder.

3 As this vicious cycle of adverse developments occur, it becomes
4 ever more costly to finance and, if not arrested, ultimately results in an
5 inability to finance. Because of the economic and market difficulties
6 now and during the last decade, it is more important than ever for
7 utilities to reduce debt ratios, increase equity ratios, control costs, and
8 seek adequate rate relief before the above mentioned vicious cycle gets
9 out of control. Only by so doing, can a utility hope to retain its credit
10 worthiness.

CREDIT EVALUATIONS

1 Q. What is meant by credit risk or the credit worthiness of long-term
2 corporate bonds?

3 A. Basically, a company's credit is determined by its expected ability to
4 pay interest and principal when due.

5 Q. How are credit evaluations made?

6 A. The large institutions, that do their own credit analysis, and the rating
7 agencies measure the company's ability to pay interest and principal
8 when due. There are many factors to measure, such as:

9

10 (1) Growth in demand for the product —
11 excessive demand resulting in a high
12 level of construction expenditures is a
13 negative in credit analysis.

14
15 (2) Level of construction program — the
16 higher the amount of construction, the
17 more credit risk there is.

18
19 (3) Quality of earnings and cash flow — large
20 amounts of allowance for funds used
21 during construction, low depreciation
22 rates, and use of flow-through account-
23 ing for rate-making purposes all have a
24 negative impact on credit worthiness.

25
26 (4) Fuel mix — from a credit point of view,
27 hydro ranks first, coal under long-term
28 contract is second, oil is third, gas is
29 fourth and nuclear is last.

30
31 (5) Adjustment clause — ability to recover
32 on a timely basis costs of fuel for elec-
33 tric generation and purchased power.

34
35 (6) Ability of the company to actually earn
36 a fair rate of return on all of its cash
37 investments.

1 Parenthetically, I would like to point out the marked realization
2 of a substantial increased risk in the utility industry growing out of the
3 Three Mile Island accident and the resulting increased costs of finan-
4 cing construction programs. The risk was present before, but the
5 accident highlighted it. If the prospective investors in equity come to
6 the conclusion that when a plant is lost or is not allowed to go into
7 commercial operation—for whatever reason—they will not receive a
8 return on their plant investment, it will not, in my judgment, be
9 possible to sell new common stock in sufficient enough quantity to
10 support the debt in the capital structure.

11 These are some of the more important areas of credit analysis
12 although the list is by no means exhaustive, especially since it does not
13 include the two most important measurements applied in corporate
14 credit analysis — interest coverage and capital structure. I will deal
15 with these two quantitative measurements separately.

16 Q. What is the interest coverage ratio?

17 A. It is a measurement of the ability of a company to make its payments in
18 full and on time. There are several ratios which are calculated but the
19 most used is the pre-tax ratio. Simply stated, this ratio is calculated by
20 dividing the amount of annual income available after all expenses —
21 except income taxes, interest and dividends — have been paid by the
22 total annual interest payments.

23 For many years this coverage ratio for utility companies averaged
24 4.0x and higher. Rapidly rising interest rates since 1965, together with

1 a declining rate of return on equity capital for most utilities, have
2 lowered these ratios precipitously.

3 Q. What are the minimum coverage ratio levels for the various categories?

4 A. Schedule 4 shows Standard & Poor's expected long-term coverage ratio
5 ranges. For electric utility companies, the expected coverage ranges
6 are 3.25x and higher for AA; 2.5x to 3.5x for A, and under 3.0x for BBB
7 electric utilities.

8 Q. Please describe how the capital structure of a utility company is used
9 as a measure of credit worthiness.

10 A. Simply stated, the more debt a company employs in its capital
11 structure, the riskier it is. Debt capital is obtained by means of a
12 contract which states that interest will be paid in a fixed amount on
13 fixed dates and that the capital will be paid back to the investor on a
14 fixed date in the future. These are fixed obligations that occur
15 regardless of the success or failure of the company. Obviously, the
16 fewer fixed obligations incurred by the company, the less the risk of
17 non-payment in the event earnings should decline sharply or even should
18 losses occur. Cyclical industries, for instance, employ very little long-
19 term debt in their capital structure because of the volatility of
20 earnings.

21 Since 1965, the business risks of the utility industry have been
22 increasing. Difficulties in maintaining productivity gains, rising fuel
23 costs, costly environmental expenditures, rising construction costs,
24 rising maintenance costs, etc., are examples of business risks which

1 were not important factors prior to 1965, but which have grown in
2 intensity since that time.

3 In addition, the inability of utility companies to recover rising
4 costs promptly through higher revenues in recent years has resulted in
5 much greater volatility of earnings, another indication of increased
6 business risk which indicates the need for a more conservative capital
7 structure.

8 Q. In your opinion, what capital structure objectives are appropriate for
9 the utility industry under the business risk circumstances of the 1980's?

10 A. If utilities are going to gain and preserve credit worthiness over the
11 next several years, they will have to recognize the increased business
12 risks and lower the financial risk. Specifically, the debt ratio target
13 should be less than 50% , the common equity ratio target should be at
14 least 40%, with the remainder accounted for by the use of preferred
15 stock.

16 Q. What are the ratings on Virginia Electric and Power Company's mort-
17 gage bonds?

18 A. As previously discussed, VEPCO's bond ratings have been lowered. In
19 1974, Standard & Poor's lowered the Company's bond ratings to A from
20 AA. Moody's also lowered the Company's bond rating to A from Aa in
21 1974. On April 26, 1982, Moody's added modifiers --1, 2 and 3-- to its
22 bond ratings, with 1 being the highest and 3 the lowest. Virginia
23 Electric and Power Company's bonds were assigned an A2 rating by
24 Moody's.

- 1 Q. Are these ratings satisfactory?
- 2 A. No. The Company should strive to eventually regain its AA/Aa bond
- 3 ratings. In order to regain AA/Aa ratings, the Company must strive to
- 4 improve the quality of its earnings, to strengthen its internal generation
- 5 and lower its need for new high cost capital.
- 6 Q. Will you quantify the financial results which you believe to be necessary
- 7 to regain AA/Aa bond ratings? --
- 8 A. In order to regain AA/Aa bond ratings, it is my opinion that the
- 9 Company must maintain a debt ratio well under 50%. Furthermore, it
- 10 must achieve and maintain a pre-tax coverage ratio in the range of 3.5x
- 11 to 4.0x.

COMMON STOCK MARKET
AND
REQUESTED RETURN ON EQUITY

1 Q. Turning now to the common stock market, would you please describe
2 the situation?

3 A. The stock market, not surprisingly, has performed poorly for the most
4 part during the 1970's and 1980's. This performance mirrors the
5 Nation's difficult circumstances of the 1970's and 1980's.

6 The long stock market decline together with the dramatic impact
7 of the dividend omission by Consolidated Edison in April, 1974, reduced
8 the prices of most utility common stocks to levels below book value.
9 The majority of utility common stocks are still selling below book
10 value.

11 Q. Have you prepared a schedule illustrating the plight of the utility
12 common stock investor in recent years?

13 A. Yes, I have. Schedule 5 traces the market performances of the New
14 York Stock Exchange Industrial and Utility indexes since the end of
15 1965, the first period the individual indexes were computed. From a
16 base of 50.0 at the end of 1965, the industrial index increased to 70.33
17 at the end of 1972. In 1974, the industrial index fell to a year-end low
18 of 39.15 and then increased to 93.02 at the end of 1982. The annual
19 rate of increase was only 2.9% since 1965. The utility index reflects an
20 even poorer performance.

1 The utility index decreased from 50.00 in 1965 to a low of 26.65
2 at the end of 1974. At year-end 1982, the utility index was only 43.47,
3 13% less than the 1965 level. The annual rate of decrease since 1965
4 was .9%.

5 It should be noted that while the industrial index has shown an
6 annual increase of only 2.9% since 1965 and the utility index decreased
7 .9% annually, the Consumer Price Index has increased at an annual rate
8 of approximately 7.0%.

9 Q. Is it not true that one of the legitimate risks faced by common stock
10 investors is the possibility that the price of the stock may well decline?

11 A. Of course it is.

12 Q. If that is the case, why should this Commission be concerned about the
13 price of Virginia Electric and Power Company's common stock?

14 A. The Commission should be greatly concerned about Virginia Electric
15 and Power Company's common stock selling below book value because
16 it has a direct impact upon the customer's rates.

17 A primary concern of the Commission should be to assure that the
18 Company avail itself of the lowest costs possible for needed goods,
19 including capital. When new equity capital must be sold at market
20 prices below book value, dilution of earnings per share and assets per
21 share occur. When such a situation continues it becomes ever more
22 difficult to issue new shares except at even lower price levels, thus
23 extending the downward cycle. The sale of stock at prices below book
24 value requires ever larger rate increases as an offset. As shown by
25 Schedule 6, the sale of common stock below book value requires a

1 higher rate of return on equity just to stay even, let alone meet the
2 requirements of the marketplace. This is obviously bad for the common
3 stockholder, and though not so obvious, it is also bad for the ratepayer.
4 When a company's financial performance results in common stock prices
5 below book value, and when, further, the company is required by its
6 public utility obligation to expand and sell new common stock at prices
7 below book value, both ratepayer and stockholder are penalized.

8 Q. What if regulation were to refuse to recognize the additional costs of
9 selling shares below book value?

10 A. Such an action would depress the market price of the stock to levels
11 even further below book value and eventually investors would refuse to
12 supply new equity capital funds at all. When that occurs, of course,
13 financing capability disappears.

14 Q. Why is the return on equity important as a measure of a company's
15 ability to attract new capital?

16 A. The dollars provided by the return on equity provide the coverage on
17 bonds, preferred stock and commercial paper, in addition to the obvious
18 earnings per share and dividends per share. Investors in common stock
19 derive their return on investments from current yield, which is the
20 dividend per share paid divided by the price per share at which they
21 purchase the stock, and from appreciation in the price of the stock,
22 which, in the long run, derives from growth in earnings per share.
23 Growth in earnings derives from earning a return on the portion of
24 earnings reinvested in the business. If the return on equity declines
25 sharply, earnings per share decline and the price of the stock declines.

1 If, however, the rate of return on equity is maintained or improved,
2 then earnings per share increase and price appreciation is possible.

3 Thus, it may be seen that the key ingredients of senior capital and
4 common stock investment costs result from the company's rate of
5 return on common equity. When the return on equity is too low,
6 coverages fall, security ratings are downgraded and the price of the
7 common stock declines below book value. So long as deterioration in
8 the rate of return on equity occurs, earnings per share will decline,
9 finally to the level of the common dividend where the decline must be
10 arrested or the dividend cannot be paid in full. If a utility company
11 begins to reduce its dividend, it is effectively foreclosed from the
12 marketplace for new capital funds.

13 Q. What is the market-determined cost of equity capital?

14 A. It is the return on equity investment required to sell new common stock
15 to the public at a price which will produce net proceeds to the issuing
16 company -- after any general market decline, issuance pressure, under-
17 writer's compensation and other issuance expenses -- of not less than
18 book value per share.

19 The cost of new common equity funds is set for a company by the
20 free market, not by a regulatory body, an investment banker or a
21 company. The free market evaluates risk in an investment and
22 establishes the rate of return on investment necessary to take those
23 risks. Capital costs decline as risks are lowered.

24 Q. Is the true cost of common equity, then, equal to a return which will

1 enable a company's common stock to trade normally at a price equal to
2 book value per share?

3 A. No. If a company is to issue new shares yielding net proceeds equal to
4 book value per share, it is necessary that the market price of the shares
5 prior to the issuance be sufficiently above book value to allow for the
6 costs of issuance (including underwriter's compensation and other
7 issuance expenses) as well as any downward market pressure on the
8 price of the stock brought about by the announcement of the new issue.
9 In addition, since a utility must raise capital when needed to fulfill its
10 public service obligation, the cost of equity must reflect the possibility
11 that the utility will be required to issue new shares of common stock
12 during unfavorable market conditions. It is my opinion that a 20%
13 premium to book value would enable a utility company to sell new
14 common at or above book value during most market conditions.

15 Q. Why have you concluded that 20% is an adequate premium to book
16 value?

17 A. The 20% premium is required to offset declines in the stock price
18 resulting from general market conditions, a decline in the price due to
19 dilution caused by the additional shares and the underwriting, legal and
20 printing costs associated with the offering of new stock. Schedule 7
21 indicates the velocity in Virginia Electric and Power Company's
22 common shares since 1974 up to the present time. Such velocity, as
23 may be noted, averaged 15.28% and was as high as 56.35% and as low as
24 2.94% in 1974. Such velocity means that for any six-month period
25 required to begin and finish the process of offering stock, the Company

1 would have been subject to price declines in the range of 2.94% to
2 56.35% over the time period since the beginning of 1974. In addition,
3 there are underwriting and issuance costs for the Company. Consider-
4 ing all these factors, it is my judgment, that a 20% premium should be
5 adequate under most circumstances to achieve net proceeds of not less
6 than book value on a new offering.

7 Q. Mr. Meyer, implicit in your testimony on the issuance of new common
8 stock at prices above or below book value is the notion that utilities
9 must issue new common stock. Why do utilities issue new securities --
10 debt, preferred stock or common stock?

11 A. Utilities issue new securities to pay for the construction of facilities
12 that provide or will provide service for existing and future customers
13 and, also, to refinance maturing securities.

14 Q. Why don't utility companies sell debt securities instead of common
15 stock when the equity return is low and the market price of the
16 common is below book value?

17 A. Many utilities have done exactly that with disastrous results. Excessive
18 debt and inadequate earnings are the primary culprits responsible for
19 bond rating reductions and the prospect of indenture violations in the
20 industry today. With ratings reductions and the prospect of indenture
21 violations comes the inability to finance, in some cases regardless of
22 price. In my judgment, utility companies must strive to reduce the
23 amount of leverage employed in their capital structures. Due primarily
24 to inflationary trends in our economy and upheaval in the world energy
25 markets, utility business risks have increased sharply. This higher risk

1 must be offset by lower financial risk; i.e., lower debt ratios and higher
2 equity ratios.

3 The Company has need for new capital now and in the years
4 ahead. The combination of continued sound financial policy and
5 realistic regulation will go a long way toward providing the Company
6 and its customers with the lowest cost of capital possible to meet the
7 needs.

8 Q. Since the issuance of excessive debt is not the viable solution, is there
9 any other way to avoid the issuance of new common stock at prices
10 below book value?

11 A. The most obvious way is to reduce capital expenditures to levels
12 justified by internally generated funds. This is the course undertaken
13 by virtually all of American business. The whole utility industry is a
14 notable exception to this rule, however. It is the utility's responsibility
15 to provide services to its customers on demand. If the utility's
16 construction program were geared to its ability to pay for new plant
17 rather than to the needs of the people it serves, in a very short time it
18 would be unable to satisfy those needs. This unnecessary hardship will
19 be avoided if the Company is able to earn the return that will attract
20 new capital at reasonable rates.

21 Q. Mr. Meyer, you mentioned earlier that the free market evaluates risks
22 and sets rates of return necessary to take those risks. What is the rate
23 of return to a common stock investor?

24 A. His rate of return is commonly called total return. This is simply the
25 sum of the current yield and the annual rate of price appreciation. It is

1 presumed that, over the long term, price appreciation will equal the
2 annual percentage increase in earnings per share.

3 Q. How is current yield calculated?

4 A. It is calculated by dividing the annual dividend per share by the price
5 per share which the investor pays. For instance, if the dividend is \$1.00
6 per share per year and the investor pays \$10 per share for the stock, the
7 current yield would be 10.00%:

8
$$\text{\$1.00 divided by \$10.00} = 10.00\%$$

9 Q. How is the earnings per share growth rate calculated?

10 A. It is calculated by multiplying the rate of return on book equity times
11 the retention rate. The retention rate is the percentage of annual
12 earnings which is retained for reinvestment. Thus, if a company pays a
13 dividend of \$1.00 per share annually and earns \$1.50 per share annually,
14 it retains \$.50 per share for reinvestment. The company's retention
15 rate is 33 1/3% calculated as follows:

16
$$\text{\$.50 divided by \$1.50} = 33 \frac{1}{3}\%$$

17 The company's earnings per share growth rate will be 6.00% per
18 year if the rate of return on book equity is 18%, calculated as follows:

19
$$33 \frac{1}{3}\% \text{ times } 18\% = 6.00\%$$

20 Q. What then is the total return to the investor in this example?

21 A. It is 16.00% calculated as follows:

22
$$\text{Current yield } 10.00\% \text{ plus } 6.00\% \text{ earnings}$$

23
$$\text{growth rate} = 16.00\% \text{ total return}$$

24

25 Q. If new common stock is sold at net proceeds above or below book value,
26 is the total return altered?

1 A. Yes, the per share earnings growth rate is somewhat lower if stock is
2 sold below book value and is somewhat higher if stock is sold above
3 book value.

4 Q. What are the risks which must be evaluated by common stock investors?

5 A. The common stock investors face all the same risks as debt and
6 preferred stock investors. That is, the value of their securities will
7 decline if the company's financial performance is inadequate. In the
8 case of business failure, however, the common stock investor is entitled
9 to nothing unless all creditors before him have been paid and there is
10 something left.

11 Q. Is the risk of bankruptcy a likely one in the utility industry?

12 A. Based on past history, it is unlikely. Because of the essential nature of
13 utility services, however, financial failure in the utility industry would
14 undoubtedly cause some government body to take over the operation.
15 Whether the common stockholder would be fairly compensated under
16 such circumstances is certainly a serious risk. As a result, the investor
17 demands a higher total return on his investment than senior security
18 investors who have a contract, presumable enforceable in a court of
19 law.

20 Q. Assuming no financial failure, as such, what are the factors which
21 utility common stock investors must evaluate?

22 A. The answer to this question derives from the total return equation
23 which I described earlier. Part of that total return is the earnings per
24 share growth rate. The common stock investor must evaluate whether
25 earnings per share will grow in the future and, if so, at what rate. To

1 do this, he will have to make judgments as to the rate of return on
2 equity that the company can earn in the future and the retention rate
3 which is likely.

4 In evaluating the future rate of return on equity, the investor
5 must consider:

- 6 (1) Whether revenue increases can keep
7 pace with cost increases.
8
- 9 (2) Whether management will control costs
10 to the best of its ability and seek rate
11 relief early enough when it is necessary.
12
- 13 (3) Whether regulation will recognize all
14 legitimate costs of doing business inclu-
15 ding the cost of equity capital with rates
16 that will enable the company to maintain
17 its financial integrity.
18
- 19 (4) Whether the company will be able to
20 earn the allowed rate of return.
21

22 The assumption on actual future rate of return on book equity is
23 dependent on many things, but, the allowable level set by the regulatory
24 commision is, of course, a critical factor. If that level is 18% and the
25 investor assumes that the Company could actually earn at that level
26 while retaining 30% of earnings, he could then expect an earnings per
27 share growth rate of 5.40% determined as follows:

28 18% R.O.E. times 30% retention = 5.40% e.p.s. growth rate

29 Q. What about the current yield part of the total return? How does the
30 investor go about evaluating this?

31 A. During the 1973 - 1979 period, the investor emphasized the current
32 yield portion of total return to a much greater degree than the earnings
33 per share growth rate portion. Schedule 8 shows that from 1973 to

1 the end of 1979, investors in utility stocks demanded a current yield
2 which approximated bond yields. Since 1980, however, the utility stock
3 current yield relative to bond yields approximates the relationship
4 established during the 1960's. It would appear, therefore, that investors
5 are now beginning to emphasize the growth portion of total return once
6 again.

7 Q. Have you analyzed Virginia Electric and Power Company as a common
8 stock investment?

9 A. I have.

10 Q. What have you considered?

11 A. A prospective investor in Virginia Electric and Power Company's
12 common stock must make estimates as to:

- 13 1. the retention rate
- 14 2. the prospective rate of return on equity
- 15 3. the safety of the dividend
- 16 4. the likelihood of dividend increases

17 Q. What are your findings on the subject of retention rate?

18 A. Virginia Electric and Power Company's retention rate has ranged from
19 31% in 1978 to 15% in 1979 and has averaged 23% during the 1978-1982
20 period. It is my opinion that a retention rate of 35% to 40% is prudent
21 for the long term. However, because interest rates are currently high,
22 it is my professional opinion that the retention ratio for Virginia
23 Electric and Power Company should be near 30%, for now.

24 Q. What are your findings as to the safety of Virginia Electric and Power
25 Company's dividend?

1 A. In 1982 the Company's dividend was \$1.525 per share relative to
 2 earnings per share of \$1.98 (including the non-cash AFUDC credit). It
 3 is obvious that the Company needs to increase its earnings if the
 4 dividend is to be maintained and increased.

5 Q. What are your findings as to the likelihood of dividend increases?

6 A. Dividend increases should occur in the utility business at a rate in line
 7 with the retention of earnings. In other words, if a company retains
 8 earnings for reinvestment for growth, the investor has a right to expect
 9 a dividend on those reinvested earnings.

10 Q. Will the Company's requested return on equity of 16% meet investor
 11 requirements at a premium to book value under current market
 12 conditions?

13 A. In order to respond to that question, it is necessary to review the
 14 current market. In the current market, Virginia Electric and Power
 15 Company's market value is \$15.00 and has ranged from \$12.00 to
 16 \$15.625 for the past year (\$13.81 average). When the \$15.00 current
 17 market price is combined with the Company's current \$1.60 dividend,
 18 the yield is 10.7%.

19 If Virginia Electric and Power Company actually earned 16% on
 20 equity, its earnings per share would be \$2.93:

21 $\$18.31$ (12/31/82 B.V.) times 16% R.O.E. = \$2.93 E.P.S.

22 With a 70% payout ratio, the dividend would be \$2.05 per share:

23 $\$2.93$ E.P.S. times 70% P.O. = \$2.05 D.P.S.

24 The dividend of \$2.05 and a 10.7% yield requirement would produce a
 25 market value of \$19.16:

1 \$2.05 D.P.S. divided by 10.7% yield = \$19.16 M.V.

2 A market value of \$19.16 is 105% of book value:

3 \$19.16 divided by \$18.31 = 105%

4 Under current market conditions, a return on equity of 16% is not
5 adequate. A return on equity greater than 16% is required if VEPCO is
6 to have the opportunity to sell new equity at or above book value under
7 most market conditions.

8 Q. Are you shocked by such high return on equity requirements?

9 A. Yes. I am also shocked by 10.50% prime rates, 12.4% long-term bond
10 rates, etc. Wishing these economic facts of life away will not make it
11 so. These are the markets into which the Company must venture for its
12 capital.

13 Q. Would you summarize your testimony?

14 A. I have attempted to describe the capital markets in which Virginia
15 Electric and Power Company must operate to attract the necessary
16 capital to provide the service required by its customers. These markets
17 reflect the Nation's difficult economic circumstances and thus create
18 pressures on the Company's ability to raise capital to meet the energy
19 requirements of the service area. In my judgment, it is within the
20 powers of the Virginia State Corporation Commission, by allowing ade-
21 quate return in today's market, and the management of Virginia
22 Electric and Power Company, by continuing to follow prudent financial
23 policies, to reduce the cost of capital to the Company and minimize the
24 rates increases of the future.

25 Q. Does this conclude your testimony?

26 A. Yes, it does.

QUALIFICATIONS

I studied at both the University of Iowa and Valparaiso University, graduating with a Bachelor of Business Administration Degree from Iowa in 1960. I joined Investors Diversified Services, Inc., Minneapolis, Minnesota, as a junior security analyst in 1960, pursuing the analysis of the electric utility industry. Later in 1960, I became senior electric utility industry analyst for IDS, and in 1964, Manager, Utility Investments, including electric, gas and telephone companies. In 1966, I joined Panhandle Eastern Pipe Line Company as Director of Financial Research and in 1967 moved to Tucker, Anthony & R. L. Day as Director of Research, becoming a general partner of that firm on January 1, 1969. I have been a Vice President with Kidder, Peabody since January 1, 1971, a member of the Board of Directors since January 1, 1973, and a member of the Management Committee since January 1, 1980. I am a member of the New York Society of Security Analysts, where I served a three-year term on the Utility Program Committee. I am a Chartered Financial Analyst, having received that designation from the Institute of Chartered Financial Analysts in 1966.

Furthermore, I have participated in the John Childs' Utility Seminars and Regulatory Seminars as a guest lecturer on the subjects, "Financial Policy from an Institutional Common Stock Buyer's Point of View", "Security Analysis", "Investment Banking" and "Dividend Policy". In addition, I have delivered addresses at various conferences of the National Association of Regulatory Utility Commissions, the Financial Analysts Federation, American Statistical Association, American Gas Association, New England Gas Association, Southern Gas Association, Public Utilities Buyers Group, Electric Council of New England, the Southeastern Electric Exchange, the New

161

York State Utility Executives Association, the National Association of Auditors, Comptrollers and Treasurers, the Edison Electric Institute National Convention, and the Rutgers University Conference on the Environment and the Energy Crisis. Since 1971, I have presented testimony in numerous rate proceedings before 54 regulatory commissions including: Alabama, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Rhode Island, South Carolina, Tennessee, Texas (Railroad Commission and the Texas Public Utility Commission), Utah, Vermont, Virginia, Washington, Wisconsin, Wyoming, the Federal Power Commission, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission and the City Councils of Dallas, El Paso, Fort Worth and Waco, Texas and New Orleans, Louisiana, the District Court of the Parish of East Baton Rouge, Louisiana and the District Court of Harris County, Texas. I have also testified before the Subcommittee on Energy Conservation and Regulation of the U.S. Senate Committee on Energy and Natural Resources concerning electric utility rate reform, the U.S. Senate Subcommittee on Anti-Trust and Monopoly Affairs concerning a bill designed to force the separation of combination utility companies, before the Securities and Exchange Commission in the Pacific Lighting divestiture proceedings, before the U.S. Price Commission in the public hearing on utility guidelines and three times before the U.S. Senate Committee on the Interior and Insular Affairs in its continuing investigation of the Nation's energy problems. I was also a member of the Electric Utility

Advisory Committee and the Energy Advisory Committee to the Federal Energy Administration.

Kidder, Peabody is engaged in investment banking, securities brokerage and investment advisory services. The firm is a member of the New York Stock Exchange, the American Stock Exchange and other principal securities exchanges. In the field of investment banking, the firm acts as the manager or co-manager of a substantial volume of public offerings of first mortgage bonds, debentures, preferred stocks and common stocks in many different industries. We also participate as an underwriter and distributor of security offerings managed by other investment banking firms. In addition, the firm is active in negotiating direct placements of security issues with institutional investors.

Since 1970, Kidder, Peabody has acted as the managing underwriter or as the co-manager of public offerings and private placements of corporate securities aggregating over \$81.0 billion, making the firm one of the largest investment banking houses in the country during this period. As measured by the volume of business transacted on the New York Stock Exchange, Kidder, Peabody is among the larger securities brokers; it is also very active in the trading of unlisted securities in the over-the-counter market.

So far as bonds, debentures and preferred stocks are concerned, our clientele is comprised primarily of institutional investors since it is this type of account which provides by far the largest source of demand for fixed income securities. So far as common stocks are concerned, the type of clientele is far more varied. We do a substantial business both with individuals and with institutional investors -- that is to say, with funds which are administered by professional investment managers. These would include

163

trust companies, investment trusts, insurance companies, pension funds, charitable institutions and the like.

Currently, the firm has over 1,600 professionally trained securities personnel brokers in 72 offices in this country and abroad, serving both individual and institutional investors.

VIRGINIA ELECTRIC AND POWER COMPANY
SELECTED STATISTICS
1972 - 1982

	<u>Operating Revenues</u> (000)	<u>Total AFUDC</u> (000)(a)	<u>Income Before Interest Charges</u> (000)(b)	<u>Total Interest Charges</u> (000)	<u>Preferred & Preference Dividends Paid</u> (000)	<u>Balance for Common Stock</u> (000)	<u>Earnings Per Share</u>		<u>Dividends Paid Per Share</u>	<u>Average Market Value</u>
							<u>W/AFUDC</u>	<u>W/O AFUDC</u>		
1972	\$ 470,853	\$ 58,451	\$ 176,453	\$ 72,716	\$ 16,472	\$ 87,265	\$ 2.08	\$.69	\$ 1.12	\$ 20.438
1973	550,963	57,359	213,106	89,034	24,147	99,925	2.13	.90	1.165	18.188
1974	764,012	65,735	232,081	117,272	30,419	84,390	1.62	.36	1.18	11.313
1975	1,033,336	66,873	297,239	142,507	35,971	118,761	1.95	.85	1.18	11.063
1976	1,104,076	80,429	321,676	154,890	43,821	122,965	1.80	.62	1.225	14.000
1977	1,358,860	99,662	364,426	174,633	47,719	142,074	1.92	.57	1.24	15.063
1978	1,464,905	88,871	395,488	191,624	53,588	150,276	1.88	.77	1.30	14.625
1979	1,703,309	95,908	413,276	216,809	55,046	141,344	1.63	.52	1.38	12.500
1980	2,119,774	112,756	504,711	263,091	57,290	184,329	1.93	.75	1.40	10.750
1981	2,161,853	84,807	562,068	324,288	57,170	180,614	1.77	.94	1.425	11.625
1982	2,360,770	83,373	599,650	321,061	56,995	221,598	1.98	1.23	1.525	13.125
Least Square Annual Growth Rate										
	17.6%	5.4%	12.7%	15.7%	12.1%	9.5%	(0.7)%	4.2%	3.0%	(3.5)%

- (a) Allowance for Funds used during Construction
(b) Includes Allowance for Funds used during Construction
(c) Excludes non-recurring cumulative effect of change in accounting for unbilled revenues of \$.24 per share.

Source: Virginia Electric and Power Company
Company Annual Reports
Compustat

Aa and A Yields
Moody's Outstanding Public Utility Bonds*
1974-1975

<u>1974</u>	<u>Aa Rate</u>	<u>A Rate</u>
January	8.15%	8.36%
February	8.20	8.42
March	8.35	8.46
April	8.56	8.77
May	8.72	9.00
June	8.93	9.32
July	9.17	9.66
August	9.53	10.03
September	10.05	10.45
October	9.93	10.78
November	9.54	10.46
December	9.37	10.27
<u>1975</u>		
January	9.45	10.37
February	9.23	9.99
March	9.17	9.72
April	9.48	10.06
May	9.50	10.23
June	9.34	10.10
July	9.38	10.01
August	9.52	10.12
September	9.64	10.19
October	9.55	10.16
November	9.45	10.04
December	9.51	10.11

* Maturities of at least 20 years.

Aa and A Yields
Moody's Outstanding Public Utility Bonds*
1979-1980

<u>1979</u>	<u>Aa Rate</u>	<u>A Rate</u>
January	9.70%	9.90%
February	9.74	9.84
March	9.89	10.04
April	9.92	10.10
May	10.19	10.30
June	9.95	10.14
July	9.72	9.98
August	9.75	10.14
September	9.94	10.36
October	10.85	11.40
November	11.57	11.89
December	11.47	11.79
 <u>1980</u>		
January	11.95	12.27
February	13.19	13.55
March	14.09	14.65
April	13.49	13.87
May	11.99	12.53
June	11.73	12.21
July	11.96	12.26
August	12.73	12.96
September	13.18	13.43
October	13.33	13.58
November	13.96	14.12
December	14.37	14.63

* Maturities of at least 20 years.

167

Aa and A Yields
Moody's Outstanding Public Utility Bonds*
1981-1982

<u>1981</u>	<u>Aa Rate</u>	<u>A Rate</u>
January	14.03%	14.26%
February	14.65	14.91
March	14.61	15.14
April	15.23	15.48
May	15.61	16.25
June	14.89	15.74
July	15.42	16.21
August	16.14	16.58
September	16.58	17.16
October	16.28	17.21
November	14.88	16.20
December	15.23	16.29
<u>1982</u>		
January	16.48	16.83
February	16.33	16.84
March	15.57	16.50
April	15.12	16.31
May	15.01	16.04
June	15.78	16.42
July	15.67	16.42
August	14.71	15.83
September	13.92	15.40
October	13.21	14.79
November	12.92	14.46
December	12.76	14.43

* Maturities of at least 20 years.

168

Aa and A Yields
Moody's Outstanding Public Utility Bonds*
1983

<u>1983</u>	<u>Aa Rate</u>	<u>A Rate</u>
January	12.74%	14.24%
February	13.02	14.26

UTILITY COMPANIES DOWNGRADED BY
MOODY'S INVESTORS SERVICE, INC.
AND/OR
STANDARD & POOR'S CORPORATION

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1970</u>				
1/14	Connecticut Light & Power	AAA	AA	Standard & Poor's
2/18	Potomac Electric Power	Aa	A	Moody's
2/25	Duke Power	AAA	AA	Standard & Poor's
2/25	Duke Power	Aaa	Aa	Moody's
4/07	Trunkline Gas	A	BBB	Standard & Poor's
4/23	Boston Gas	A	BBB	Standard & Poor's
5/13	Monogahela Power	AA	A	Standard & Poor's
6/04	Kansas City Power & Light	AAA	AA	Standard & Poor's
6/15	Appalachian Power	AA	A	Standard & Poor's
6/22	Boston Edison	AAA	AA	Standard & Poor's
7/02(a)	Jamaica Water Supply	A	BBB	Standard & Poor's
8/27	Southern Connecticut Gas	A	BBB	Standard & Poor's
8/27	Southern Connecticut Gas	A	Baa	Moody's
9/15	Ohio Edison	AAA	AA	Standard & Poor's
9/29	Carolina Telephone & Telegraph	Aa	A	Moody's
9/29	Carolina Telephone & Telegraph	AA	A	Standard & Poor's
9/29	Elizabethtown Gas	AA	A	Standard & Poor's
9/29	Elizabethtown Gas	Aa	A	Moody's
12/01	Ohio Power	Aa	A	Moody's
12/02	New England Power	AA	A	Standard & Poor's
12/07	New Bedford Gas & Electric	AA	A	Standard & Poor's
12/08	Iowa Electric Light & Power	AA	A	Standard & Poor's
12/10	Philadelphia Electric	Aaa	Aa	Moody's
<u>1971</u>				
1/13	Florida Power & Light	AA	A	Standard & Poor's
2/01	Pennsylvania Power & Light	AA	A	Standard & Poor's
2/18	Jersey Central Power & Light	A	BBB	Standard & Poor's
4/01	Ohio Power	AA	A	Standard & Poor's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1971</u>				
(Cont'd)				
5/04	Wisconsin Public Service	AA	A	Standard & Poor's
5/11	Southern New England Telephone	AAA	AA	Standard & Poor's
6/03	Kansas City Power & Light	Aaa	Aa	Moody's
8/10	Consumers Power	AAA	AA	Standard & Poor's
8/19	Pennsylvania Electric	A	BBB	Standard & Poor's
8/26	Hawaiian Telephone	Aa	A	Moody's
8/26	Hawaiian Telephone	AA	A	Standard & Poor's
10/19	Carolina Power & Light	Aa	A	Moody's
10/19	Carolina Power & Light	AA	A	Standard & Poor's
11/03	Metropolitan Edison	A	BBB	Standard & Poor's
11/29	Iowa Power & Light	AA	A	Standard & Poor's
11/29	Orange & Rockland Utilities	A	Baa	Moody's
11/29	Orange & Rockland Utilities	A	BBB	Standard & Poor's
11/29	Rockland Electric	A	Baa	Moody's
11/29	Rockland Electric	A	BBB	Standard & Poor's
11/29	Rockland Light & Power	A	Baa	Moody's
11/29	Rockland Light & Power	A	BBB	Standard & Poor's
<u>1972</u>				
1/17	Kentucky Power	A	BBB	Standard & Poor's
2/03	Niagara Mohawk Power	AA	A	Standard & Poor's
2/09	Central Hudson Gas & Electric	AA	A	Standard & Poor's
#	Central Vermont Public Service	A	BBB	Standard & Poor's
2/24	Columbus & So. Ohio Electric	AA	A	Standard & Poor's
3/11#	Rochester Gas & Electric	AA	A	Standard & Poor's
3/22	New England Telephone & Telegraph	AAA	AA	Standard & Poor's
#	Iowa-Illinois Gas & Electric	AA	A	Standard & Poor's
#	New Jersey Power & Light	A	BBB	Standard & Poor's
5/17	Pennsylvania Power	AA	A	Standard & Poor's
6/06	Consumers Power	Aaa	Aa	Moody's
6/12	Cambridge Electric Light	AA	A	Standard & Poor's
6/29	Baltimore Gas & Electric	AAA	AA	Standard & Poor's
8/14#	New Jersey Power & Light	A	Baa	Moody's
8/16	Jersey Central Power & Light	A	Baa	Moody's
12/05	Duke Power	AA	A	Standard & Poor's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1972</u>				
(Cont'd)				
12/12	Georgia Power	Aa	A	Moody's
12/12	Georgia Power	AA	A	Standard & Poor's
12/16#	Canal Electric	AA	A	Standard & Poor's
<u>1973</u>				
2/05	Commonwealth Edison	AAA	AA	Standard & Poor's
2/14	Consolidated Edison of New York	A	BBB	Standard & Poor's
3/24#	Indiana & Michigan Electric	AA	A	Standard & Poor's
4/14#	Boston Edison	AA	A	Standard & Poor's
5/31	Pacific Telephone & Telegraph	AAA	AA	Standard & Poor's
6/13	Atlantic City Electric	AA	A	Standard & Poor's
9/19	Natural Gas Pipeline	Aa	A	Moody's
11/12	Duke Power	Aa	A	Moody's
12/10#	Boston Edison	Aa	A	Moody's
<u>1974</u>				
1/07	San Diego Gas & Electric	AA	A	Standard & Poor's
2/05	Union Electric	AA	A	Standard & Poor's
3/06	Public Service Co. New Hampshire	A	Baa	Moody's
3/06	Public Service Co. New Hampshire	A	BBB	Standard & Poor's
3/07	Consolidated Edison of New York	A	Baa	Moody's
3/17#	Jamaica Water	Withdrawn		Moody's
3/21	Connecticut Light & Power	AA	A	Standard & Poor's
4/01	Baltimore Gas & Electric	Aaa	Aa	Moody's
4/02	Wisconsin Power & Light	AA	A	Standard & Poor's
4/09	Hartford Electric Light	AA	A	Standard & Poor's
4/18	Western Massachusetts Electric	Aa	A	Moody's
4/18	Western Massachusetts Electric	AA	A	Standard & Poor's
4/27#	Consolidated Edison of New York	BBB	BB	Standard & Poor's
5/14	Detroit Edison	Aa	A	Moody's
5/14	Detroit Edison	AA	A	Standard & Poor's
5/01	Cleveland Electric Illuminating	AAA	AA	Standard & Poor's
5/06#	Central Vermont Public Service	Withdrawn		Moody's

172

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1974</u>				
(Cont'd)				
5/06#	Iowa Electric Light & Power	Aa	A	Moody's
5/07	Columbus & So. Ohio Electric	Aa	A	Moody's
5/13#	Consolidated Edison of New York	Withdrawn		Moody's
5/13#	Savannah Electric & Power	A	Baa	Moody's
5/20#	Blackstone Valley Electric	A	Baa	Moody's
5/20#	Brockton Edison	A	Baa	Moody's
5/20#	Eastern Utilities Associates	Baa	Ba	Moody's
5/20#	Fall River Electric Light	A	Baa	Moody's
5/28	Ohio Power	A	Baa	Moody's
6/04	Central Illinois Light	AA	A	Standard & Poor's
6/08#	Savannah Electric & Power	A	BBB	Standard & Poor's
6/13	Delmarva Power & Light	Aa	A	Moody's
6/13	Delmarva Power & Light	AA	A	Standard & Poor's
6/17	Long Island Lighting	AA	A	Standard & Poor's
6/24	Virginia Electric Power	Aa	A	Moody's
6/24	Virginia Electric Power	AA	A	Standard & Poor's
6/26	Boston Edison	A	BBB	Standard & Poor's
6/26	Boston Edison	A	Baa	Moody's
7/15#	Connecticut Light & Power	Aa	A	Moody's
7/15#	Hartford Electric Light	Aa	A	Moody's
7/17	Consumers Power	Aa	A	Moody's
7/17	Consumers Power	AA	A	Standard & Poor's
7/23	Toledo Edison	AA	A	Standard & Poor's
8/05#	Pennsylvania Power	Aa	A	Moody's
8/12	Florida Power	Aa	A	Moody's
8/20	Ohio Edison	Aaa	Aa	Moody's
9/21	Florida Power	AA	A	Standard & Poor's
10/01	Detroit Edison	A	Baa	Moody's
10/01	Detroit Edison	A	BBB	Standard & Poor's
10/03	New York State Electric & Gas	AA	A	Standard & Poor's
10/08	Southern California Gas	AA	A	Standard & Poor's
10/08	Niagara Mohawk Power	A	BBB	Standard & Poor's
10/17	Philadelphia Electric	Aa	A	Moody's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1974</u>				
(Cont'd)				
10/17	Philadelphia Electric	AA	A	Standard & Poor's
10/22	Dayton Power & Light	Aa	A	Moody's
10/22	Dayton Power & Light	AA	A	Standard & Poor's
10/29	Ohio Power	A	BBB	Standard & Poor's
11/19	Cincinnati Gas & Electric	AAA	AA	Standard & Poor's
11/19	Cincinnati Gas & Electric	Aaa	Aa	Moody's
11/19SS	San Diego Gas & Electric	Aa	A	Moody's
11/19	Florida Power & Light	Aa	A	Moody's
12/05	Nevada Power	A	BBB	Standard & Poor's
12/23#	Consumers Power	A	Baa	Moody's
12/23#	Georgia Power	A	Baa	Moody's
<u>1975</u>				
1/09	Western Massachusetts Electric	A	Baa	Moody's
1/09	Western Massachusetts Electric	A	BBB	Standard & Poor's
1/22	Columbus & So. Ohio Electric	A	BBB	Standard & Poor's
1/23	Hartford Electric Light	A	BBB	Standard & Poor's
1/25#	Georgia Power	A	BBB	Standard & Poor's
1/25#	Savannah Electric & Power	BBB	BB	Standard & Poor's
1/27#	Georgia Power	Withdrawn		Moody's
1/27#	Savannah Electric & Power	Withdrawn		Moody's
2/10#	Appalachian Power	A	Baa	Moody's
2/19	Arizona Public Service	A	Baa	Moody's
2/24	Houston Lighting & Power	Aaa	Aa	Moody's
2/24	Houston Lighting & Power	AAA	AA	Standard & Poor's
2/24#	Indiana & Michigan Electric	A	Baa	Moody's
2/25	Louisville Gas & Electric	AAA	AA	Standard & Poor's
3/03#	Iowa Electric Light & Power	A	Baa	Moody's
3/13**	Carolina Power & Light	A	Baa	Moody's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1975</u>				
(Cont'd)				
3/19C	Union Electric	Aa	A	Moody's
4/08	Cleveland Electric Illuminating	Aaa	Aa	Moody's
4/22	Appalachian Power	A	BBB	Standard & Poor's
4/24	Indiana & Michigan Electric	A	BBB	Standard & Poor's
5/01	Pacific Power & Light	A	Baa	Moody's
5/06	San Diego Gas & Electric	A	Baa	Moody's
6/24	United Illuminating	AA	A	Standard & Poor's
6/28#	Central Maine Power	A	BBB	Standard & Poor's
7/12#	Ohio Edison	AA	A	Standard & Poor's
9/06#	Eastern Utilities Associates	BBB	BB	Standard & Poor's
9/06#	Blackstone Valley Electric	A	BBB	Standard & Poor's
9/06#	Fall River Electric Light	A	BBB	Standard & Poor's
9/29#	Nevada Power	A	Baa	Moody's
10/08	Toledo Edison	Aa	A	Moody's
11/05	Central Hudson Gas & Electric	Aa	A	Moody's
11/18	El Paso Electric	Aa	A	Moody's
11/29#	San Diego Gas & Electric	A	BBB	Standard & Poor's
<u>1976</u>				
1/21	Hackensack Water	Aa	A	Moody's
1/21	Hackensack Water	AA	A	Standard & Poor's
5/05	Central Illinois Light	Aa	A	Moody's
5/10	New York State Electric & Gas	Aa	A	Moody's
6/12#	Pacific Power & Light	A	BBB	Standard & Poor's
6/24	Toledo Edison	A	Baa	Moody's
7/05	Alabama Power	A	Baa	Moody's
7/20	Ohio Edison	Aa	A	Moody's
8/07#	Alabama Power	A	BBB	Standard & Poor's
8/23#	Arkansas Power & Light	A	Baa	Moody's
9/28#	Gulf Power	Aa	A	Moody's
12/14	Louisiana Power & Light	A	Baa	Moody's
12/06	Jamaica Water Supply	Baa	Ba	Moody's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
1977				
1/24#	The Montana Power Company	Aa	A	Moody's
3/05#	The Montana Power Company	AA	A	Standard & Poor's
10/11	Southern California Gas	Aa	A	Moody's
11/16	Kansas City Power & Light	AA	A	Standard & Poor's
1978				
1/11	Pacific Telephone & Telegraph	Aaa	Aa	Moody's
1/18	Louisiana Power & Light	A	BBB	Standard & Poor's
3/21	Kansas Gas & Electric	Aa	A	Moody's
4/03#	Idaho Power	Aa	A	Moody's
4/19	Pennsylvania Power	A	Baa	Moody's
6/27	Pacific Telephone & Telegraph	AA	A	Standard & Poor's
7/29#	Kansas Gas & Electric	AA	A	Standard & Poor's
8/07#	Potomac Edison	A	Baa	Moody's
9/23#	Brockton Edison	A	BBB	Standard & Poor's
11/30#	Gulf States Utilities	AA	A	Standard & Poor's
12/02#	United Illuminating	A	BBB	Standard & Poor's
1979				
1/15#	Commonwealth Edison	Aaa	Aa	Moody's
2/05#	Monogahela Power	A	Baa	Moody's
2/07	Pacific Telephone & Telegraph	Aa	A	Moody's
2/20	Duquesne Light	Aa	A	Moody's
4/04	Gulf States Utilities	Aa	A	Moody's
4/23#	Pennsylvania Electric	A	Baa	Moody's
4/23#	Metropolitan Edison	Withdrawn		Moody's
4/28#	Metropolitan Edison	A	BBB	Standard & Poor's
4/24	Gulf Power	AA	A	Standard & Poor's
6/21**	Arkansas Power & Light	A	BBB	Standard & Poor's
7/02#	Metropolitan Edison Reinstated		Baa	Moody's
8/17S	Long Island Lighting	Aa	A	Moody's
11/07**	Commonwealth Edison	Aa	A	Moody's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1980</u>				
2/02#	Metropolitan Edison	BBB	BB	Standard & Poor's
2/02#	Jersey Central Power & Light	A	BBB	Standard & Poor's
2/26	Public Service Co. of Colorado	Aa	A	Moody's
2/26	Public Service Co. of Colorado	AA	A	Standard & Poor's
3/08#	Mississippi Power & Light	A	BBB	Standard & Poor's
3/19**	New Orleans Public Service	A	BBB	Standard & Poor's
3/26	Kansas Gas & Electric	A	Baa	Moody's
3/26	Kansas Gas & Electric	A	BBB	Standard & Poor's
3/31#	Jersey Central Power & Light	Baa	Ba	Moody's
3/31#	Metropolitan Edison	Baa	B	Moody's
3/31#	Pennsylvania Electric	Baa	Ba	Moody's
4/05#	Ohio Edison	A	BBB	Standard & Poor's
4/12#	Philadelphia Electric	A	BBB	Standard & Poor's
4/19#	Consumers Power	A	BBB	Standard & Poor's
4/28#	United Illuminating	A	Baa	Moody's
6/21#	Commonwealth Edison	AA	A	Standard & Poor's
6/23#	Long Island Lighting	A	Baa	Moody's
7/07#	Kansas City Power & Light	Aa	A	Moody's
7/12#S	Long Island Lighting	A	BBB	Standard & Poor's
8/26#	Missouri Power & Light	A	BBB	Standard & Poor's
8/30#	Dayton Power & Light	A	BBB	Standard & Poor's
9/13#	Hartford Electric Light	A	BBB	Standard & Poor's
9/13#	Oklahoma Gas & Electric	AA	A	Standard & Poor's
9/16	Connecticut Light & Power	A	BBB	Standard & Poor's
9/20	Pennsylvania Power	A	BBB	Standard & Poor's
9/23	Duquesne Light	AA	A	Standard & Poor's
10/08	Toledo Edison	A	BBB	Standard & Poor's
11/25	Central Hudson Gas & Electric	A	Baa	Moody's
12/02	New York State Electric & Gas	A	Baa	Moody's
12/03	Houston Lighting & Power	Aa	A	Moody's
12/06#	New York State Electric & Gas	A	BBB	Standard & Poor's
12/08#	Consumers Power	A	Baa	Moody's
12/15#	Michigan Consolidated Gas	A	Baa	Moody's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1981</u>				
1/31#	Jersey Central Power & Light	BBB	BB	Standard & Poor's
1/31#	Metropolitan Edison	BB	B	Standard & Poor's
1/31#	Pennsylvania Electric	BBB	BB	Standard & Poor's
2/11	Union Electric	A	BBB	Standard & Poor's
2/11	Union Electric	A	Baa	Moody's
3/14#	Duquesne Light	A	BBB	Standard & Poor's
3/14#	General Telephone Co. of California	A	BBB	Standard & Poor's
3/21#	Michigan Consolidated Gas	A	BBB	Standard & Poor's
4/04#	Kentucky Utilities	AA	A	Standard & Poor's
4/10	Utah Power & Light	AA	A	Standard & Poor's
5/02	National Fuel Gas	A	BBB	Standard & Poor's
5/05	El Paso Electric	AA	A	Standard & Poor's
5/13	Cincinnati Gas & Electric	AA	A	Standard & Poor's
6/08#	Louisville Gas & Electric	Aaa	Aa	Moody's
6/15#	Philadelphia Electric	A	Baa	Moody's
7/14	Ohio Edison	A	Baa	Moody's
7/24	Cleveland Electric Illuminating	AA	A	Standard & Poor's
7/24	Cleveland Electric Illuminating	Aa	A	Moody's
7/24	Northern Indiana Public Service	AA	A	Standard & Poor's
10/03#	Sierra Pacific Power	A	BBB	Standard & Poor's
11/17	Public Service Co. Indiana	Aa	A	Moody's
11/17	Public Service Co. Indiana	Aa	A	Standard & Poor's
11/30	Houston Lighting & Power	Aa	A	Standard & Poor's
12/21#	Central Louisiana Electric	A	BBB	Standard & Poor's
<u>1982</u>				
1/18#	Pacific Gas & Electric	Aa	A	Moody's
2/08#	Gulf States Utilities	A	BBB	Standard & Poor's
2/08#	Gulf States Utilities	A	Baa	Moody's
3/10	Commonwealth Edison	A	BBB	Standard & Poor's
3/10SS	Washington Water Power	A	BBB	Standard & Poor's
3/30	Idaho Power	A	Baa	Moody's
4/13	Pennsylvania Power & Light	A	BBB	Standard & Poor's
5/13#	New York State Electric & Gas	Baa1	Baa2	Moody's
5/14#	Long Island Lighting	A3	Baa1	Moody's
5/17#	Atlanta Gas Light	A	A-	Standard & Poor's
5/18#	Kansas Gas & Electric	BBB	BBB-	Standard & Poor's
5/19	Pacific Gas & Electric	AA-	A	Standard & Poor's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1982</u>				
(Cont'd)				
5/31#	Washington Gas Light	A	A-	Standard & Poor's
6/08	Public Service Co. New Hampshire	BBB-	BB+	Standard & Poor's
7/19#	Hydro - Quebec	Aa	A1	Moody's
7/21	Utah Power & Light	A+	A	Standard & Poor's
7/27#	Kansas City Power & Light	A3	Baa2	Moody's
7/27#	Kansas City Power & Light	A	BBB	Standard & Poor's
7/29**	Fitchburg Gas & Electric	BBB	BB+	Standard & Poor's
7/30#	Detroit Edison	Baa2	Baa3	Moody's
8/03	El Paso Electric	A+	A	Standard & Poor's
8/04**	Public Service Co. New Hampshire	Baa3	Ba1	Moody's
8/11#	Sierra Pacific Power	A3	Baa1	Moody's
8/16#	Kentucky Power	A3	Baa1	Moody's
8/16#	General Telephone Co. of California	A3	Baa1	Moody's
8/18#	Union Electric	Baa1	Baa2	Moody's
8/23#	Public Service Co. Indiana	A	BBB+	Standard & Poor's
8/30#	Public Service Electric & Gas	AA	AA-	Standard & Poor's
8/30#	Union Electric	BBB	BBB-	Standard & Poor's
9/13#	Philadelphia Electric	BBB	BBB-	Standard & Poor's
9/13#	Philadelphia Electric Power	BBB	BB+	Standard & Poor's
9/14#	Public Service Co. New Mexico	Aa2	A1	Moody's
10/04#	Public Service Co. New Mexico	AA	A	Standard & Poor's
10/13#	Pennsylvania Power & Light	Aa3	A2	Moody's
10/28#	Mississippi Power & Light	A3	Baa2	Moody's
10/28#	New Orleans Public Service	A3	Baa3	Moody's
11/5#	Public Service Co. Indiana	A2	A3	Moody's
11/8#	Washington Gas Light	A2	A3	Moody's
11/15#	Cincinnati Gas & Electric	Aa3	A1	Moody's
11/11#	Carolina Power & Light	A	A-	Standard & Poor's
12/20#	Atlanta Gas Light	A-	BBB	Standard & Poor's
12/20#	Oneok Inc.	AA-	A	Standard & Poor's
12/20#	Michigan Consolidated Gas	BBB+	BBB-	Standard & Poor's
12/20#	Northwest Natural Gas	A	A-	Standard & Poor's

*DATE	COMPANY	SENIOR RATING REDUCED		
		FROM	TO	BY
<u>1982</u>				
12/20#	El Paso Natural Gas	Baa1	Baa2	Moody's
12/20#	Fitchburg Gas & Electric	Baa3	Ba2	Moody's
12/20#	Atlanta Gas Light	A3	Baa1	Moody's
<u>1983</u>				
1/31#	Philadelphia Electric	Baa2	Baa3	Moody's
2/04#	Northern Indiana Public Service	A	BBB	Standard & Poor's
2/10	Michigan Consolidated Gas	Baa2	Baa3	Moody's
2/14#	New Orleans Public Service	BBB+	BBB-	Standard & Poor's
2/18**	Illinois Power	AA-	A	Standard & Poor's
3/08#	Long Island Lighting	Baa2	Baa1	Moody's
3/11#	American Telephone & Telegraph	Aaa	Aa1	Moody's
3/11#	Bell Telephone Co. of Pennsylvania	Aaa	Aa2	Moody's
3/11#	Chesapeake & Potomac Telephone	Aaa	A2	Moody's
3/11#	Chesapeake & Potomac Telephone Company of Maryland	Aaa	A2	Moody's
3/11#	Chesapeake & Potomac Telephone Company of Virginia	Aaa	Aa3	Moody's
3/11#	Chesapeake & Potomac Telephone Company of West Virginia	Aaa	A3	Moody's
3/11#	Cincinnati Bell, Inc.	Aaa	Aa2	Moody's
3/11#	Diamond State Telephone	Aaa	Aa2	Moody's
3/11#	Illinois Bell Telephone	Aaa	Aa3	Moody's
3/11#	Indiana Bell Telephone Company, Inc.	Aaa	Aa2	Moody's
3/11#	Michigan Bell Telephone	Aaa	A3	Moody's
3/11#	Mountain States Tel. & Tel.	Aaa	A2	Moody's
3/11#	New England Tel. & Tel.	Aaa	Aa3	Moody's
3/11#	New Jersey Bell Telephone	Aaa	Aa1	Moody's
3/11#	New York Telephone	Aaa	A1	Moody's
3/11#	New York Telephone	Aaa	Aa3	Moody's
3/11#	Northwestern Bell Telephone	Aaa	Aa3	Moody's
3/11#	Ohio Bell Telephone	Aaa	A1	Moody's
3/11#	Pacific Northwest Bell Telephone	Aaa	A1	Moody's
3/11#	Pacific Telephone & Telegraph	A3	Baa1	Moody's
3/11#	South Central Bell Telephone	Aaa	A1	Moody's
3/11#	Southern Bell Tel. & Tel.	Aaa	A1	Moody's

180

3/11#	Southwestern Bell Telephone	Aaa	A2	Moody's
3/11#	Wisconsin Telephone	Aaa	Aa3	Moody's
3/14#	Missouri Power & Light	BBB	BBB-	Standard & Poor's

* Represents date of new issue.
** Preferred offering
New debt offering not involved. Date, where shown, is Agency's publication date.
(a) Private Placement
SS Sale was postponed.
C Correction
S Same rating as Company's General and Refunding Bonds.

Note: Assumed debt of predecessor not listed. Rating changes within the rating categories are recorded effective May 1982. Prior to April 26, 1982, Moody's did not have modifiers for its bond ratings.

Source: Moody's Bond Survey
Standard & Poor's Bond Outlook, Fixed Income Investor and CreditWeek.

EARNINGS ADEQUACY
EXPECTED LONG-TERM COVERAGE RATIO RANGES - PRETAX COVERAGE OF TOTAL INTEREST

<u>Senior Debt Rating</u>	<u>Industrial Companies</u>	<u>Electric Companies*</u>	<u>Telephone Companies</u>		<u>Gas Companies</u>	<u>Water Companies</u>
			<u>Bell</u>	<u>Independents</u>	<u>Non-Diversified</u>	
AAA	12X and Higher	4.25X and Higher	4.25 - 6X	--	--	--
AA	7.5 - 12X	3.25X and Up	--	3.75 - 6X	4 - 6X	3 - 4X
A	5 - 8.5X	2.5 - 3.5X	--	3 - 4X	3.0 - 4.5X	2.5 - 3.25X
BBB	3.5 - 6X	Under 3.0X	--	2.25 - 3X	2 - 3X	2 - 2.5X

Note: These are BROAD LONG-TERM ranges of a SINGLE financial ratio. Since there are several additional ways to measure Earnings Adequacy, and since Earnings Adequacy is only one of twelve rating criteria, one should guard against over-reliance on this ratio, particularly at a single point in time. Thus, it should be clear that coverages falling into a range will not, by themselves, qualify a company for such a rating, nor will it preclude a rating change into another category.

Coverages are often adjusted for significant rentals and other debt-like obligations.

When AFUDC exceeds 10% of pretax coverage (i.e., 40 basis points of 4.0X coverage), the pretax coverage excluding AFUDC assumes importance. All AFUDC is included in gross income instead of being subtracted from interest charges.

For diversified utilities, coverages are broken down and calculated for both utility and non-utility businesses.

Source: Standard & Poor's Corporation Bond Rating Seminar
December 1979
December 1980
* December 1981

181

**New York Stock Exchange Common Stock Indexes
and Consumer Price Index
1965-1982**

<u>Year</u>	<u>Industrial</u>	<u>Utility</u>	<u>Consumer Price Index</u>
1965	50.00	50.00	94.5
1966	43.13	45.19	97.2
1967	56.59	43.38	100.0
1968	61.69	45.82	104.2
1969	54.74	38.77	109.8
1970	52.91	40.82	116.3
1971	60.53	39.39	121.3
1972	70.33	42.17	125.3
1973	56.60	34.33	133.1
1974	39.15	26.65	147.7
1975	52.73	33.47	161.2
1976	63.36	41.27	170.5
1977	56.43	40.54	181.5
1978	58.87	37.69	195.4
1979	70.24	36.90	217.4
1980	91.52	38.45	246.8
1981	80.89	40.05	272.4
1982	93.02	43.47	289.1
Least Square Annual Growth Rate	2.9%	(0.9)%	7.0%

Source: New York Stock Exchange Common Stock Indexes
EEI Pocketbook of Electric Utility Industry Statistics
Economic Indicators
Data Resources Inc.

EFFECT OF SELLING COMMON STOCK BELOW BOOK VALUE COMPANY A

Assume that Company A has \$1,000 invested in equity and has 100 shares outstanding. Assume further that Company A is earning 16% on its equity. In that case, it has earnings for common stock of \$1.60 per share:

$$\begin{aligned} \$1,000 \text{ equity} \times 16\% \text{ rate of return} &= \$160 \text{ earnings} \\ \$160 \text{ divided by } 100 \text{ shares} &= \$1.60 \text{ earnings per share} \end{aligned}$$

It may also be seen that Company A's book value per share is \$10:

$$\$1,000 \text{ equity divided by } 100 \text{ shares} = \$10 \text{ per share book value}$$

Let us now further assume that Company A requires new common equity from the sale of new stock and that its stock is selling for \$8 per share on the market; 20% below book value. When Company A sells 10 new shares of stock at \$8 per share, it realizes new equity proceeds of \$80 before issuance costs:

$$10 \text{ shares} \times \$8 \text{ per share price} = \$80 \text{ new equity}$$

Company A now has equity investment of \$1,080:

$$\$1,000 \text{ old equity} + \$80 \text{ new equity} = \$1,080$$

In addition, Company A now has 110 shares outstanding:

$$100 \text{ old shares} + 10 \text{ new shares} = 110 \text{ shares outstanding}$$

Thus, the book value per share of Company A is now \$9.82, down from \$10 before the sale:

$$\$1,080 \text{ equity divided by } 110 \text{ shares} = \$9.82 \text{ per share}$$

Furthermore, if Company A continues to earn 16% on its equity investment as before, earnings per share will decline, as well, to \$1.57 per share from the previous \$1.60 per share:

$$\begin{aligned} 16\% \text{ rate of return} \times \$1,080 \text{ equity} &= \$172.80 \\ \$172.80 \text{ earnings divided by } 110 \text{ shares} &= \$1.57 \text{ per share} \end{aligned}$$

In order to merely maintain earnings per share of \$1.60 after the sale of common shares below book value, the Company must now have earnings of \$176:

$$\begin{array}{lcl} 110 \text{ shares outstanding X} & & \\ \$1.60 \text{ earnings per share} & = & \$176 \text{ earnings} \end{array}$$

To earn \$176, however, Company A must have a rate of return on equity of approximately 16.30%, i.e.:

$$\begin{array}{lcl} \$1,080 \text{ equity X } 16.3\% \text{ rate of return} & = & \$176 \text{ earnings} \end{array}$$

VIRGINIA ELECTRIC & POWER COMPANY

MARKET FLUCTUATIONS

1974

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 15.250	\$ 8.875	41.80%
FEB.	15.750	6.875	56.35(**)
MAR.	15.250	6.875	54.92
APR.	14.250	6.875	51.75
MAY	13.125	6.875	47.62
JUNE	11.875	6.875	42.11
JULY	10.125	6.875	32.10
AUG.	9.375	7.000	25.33
SEP.	9.125	7.750	15.07
OCT.	10.000	7.750	22.50
NOV.	9.000	7.750	13.89
DEC.	8.500	8.250	2.94(*)

1975

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 11.875	\$ 10.250	13.68%
FEB.	12.500	10.250	18.00
MAR.	12.250	10.375	15.31
APR.	11.625	10.375	10.75
MAY	12.250	10.750	12.24
JUNE	13.625	11.375	16.51
JULY	13.000	11.375	12.50
AUG.	12.625	11.500	8.91
SEP.	12.250	11.500	6.12
OCT.	13.625	12.625	7.34
NOV.	13.875	12.375	10.81
DEC.	13.875	12.250	11.71

186

VIRGINIA ELECTRIC & POWER COMPANY

MARKET FLUCTUATIONS1976

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 14.875	\$ 12.250	17.65%
FEB.	14.750	12.250	16.95
MAR.	13.875	12.250	11.71
APR.	13.875	12.250	11.71
MAY	13.750	12.250	10.91
JUNE	14.000	13.500	3.57
JULY	14.125	13.625	3.54
AUG.	15.500	14.000	9.68
SEP.	15.500	14.000	9.68
OCT.	15.500	14.000	9.68
NOV.	15.000	14.000	6.67
DEC.	15.750	14.000	11.11

1977

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 16.125	\$ 14.000	13.18%
FEB.	15.625	14.000	10.40
MAR.	14.875	14.125	5.04
APR.	15.000	14.125	5.83
MAY	15.500	14.000	9.68
JUNE	15.500	14.000	9.68
JULY	15.750	14.000	11.11
AUG.	15.750	13.500	14.29
SEP.	15.000	13.500	10.00
OCT.	15.500	13.500	12.90
NOV.	15.250	13.500	11.48
DEC.	14.750	13.500	8.47

VIRGINIA ELECTRIC & POWER COMPANY

MARKET FLUCTUATIONS

1978

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 14.500	\$ 13.500	6.90%
FEB.	14.625	13.500	7.69
MAR.	14.375	13.500	6.09
APR.	14.250	13.500	5.26
MAY	14.250	13.625	4.39
JUNE	14.375	13.625	5.22
JULY	15.375	13.625	11.38
AUG.	15.750	13.250	15.87
SEP.	14.750	13.000	11.86
OCT.	14.750	12.000	18.64
NOV.	14.750	12.000	18.64
DEC.	14.250	12.000	15.79

1979

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 14.750	\$ 12.000	18.64%
FEB.	14.750	12.000	18.64
MAR.	13.875	11.875	14.41
APR.	13.000	10.625	18.27
MAY	13.000	10.625	18.27
JUNE	13.500	10.250	24.07
JULY	13.250	10.250	22.64
AUG.	13.125	9.750	25.71
SEP.	12.750	9.125	28.43
OCT.	12.125	9.125	24.74
NOV.	11.875	9.125	23.16
DEC.	11.125	9.125	17.98

VIRGINIA ELECTRIC & POWER COMPANY

MARKET FLUCTUATIONS

1980

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 12.375	\$ 9.125	26.26%
FEB.	10.750	9.125	15.12
MAR.	10.250	9.750	4.88
APR.	11.375	10.250	9.89
MAY	12.000	9.875	17.71
JUNE	12.250	9.500	22.45
JULY	12.000	9.500	20.83
AUG.	11.625	9.500	18.28
SEP.	11.250	9.500	15.56
OCT.	11.125	9.500	14.61
NOV.	11.000	9.500	13.64
DEC.	11.000	10.125	7.95

1981

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 11.875	\$ 10.125	14.74%
FEB.	11.500	10.125	11.96
MAR.	11.625	10.625	8.60
APR.	11.625	10.125	12.90
MAY	11.875	10.125	14.74
JUNE	12.375	10.125	18.18
JULY	12.125	10.125	16.49
AUG.	12.500	10.125	19.00
SEP.	11.875	10.125	14.74
OCT.	12.000	11.125	7.29
NOV.	13.125	11.125	15.24
DEC.	12.750	11.125	12.75

189

VIRGINIA ELECTRIC & POWER COMPANY

MARKET FLUCTUATIONS

1982

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 12.000	\$ 11.625	3.13%
FEB.	12.375	11.875	4.04
MAR.	12.875	12.000	6.80
APR.	13.500	12.000	11.11
MAY	13.625	12.000	11.93
JUNE	13.125	12.500	4.76
JULY	13.375	12.750	4.67
AUG.	14.625	13.000	11.11
SEP.	14.250	N/A	N/A
OCT.	14.875	N/A	N/A
NOV.	15.125	N/A	N/A
DEC.	14.500	N/A	N/A

1983

<u>MONTH</u>	<u>HIGH</u>	<u>NEXT SIX MONTHS LOW</u>	<u>PERCENT CHANGE</u>
JAN.	\$ 15.250	N/A	N/A
FEB.	15.625	N/A	N/A

(*) LOWEST CHANGE - 2.94%

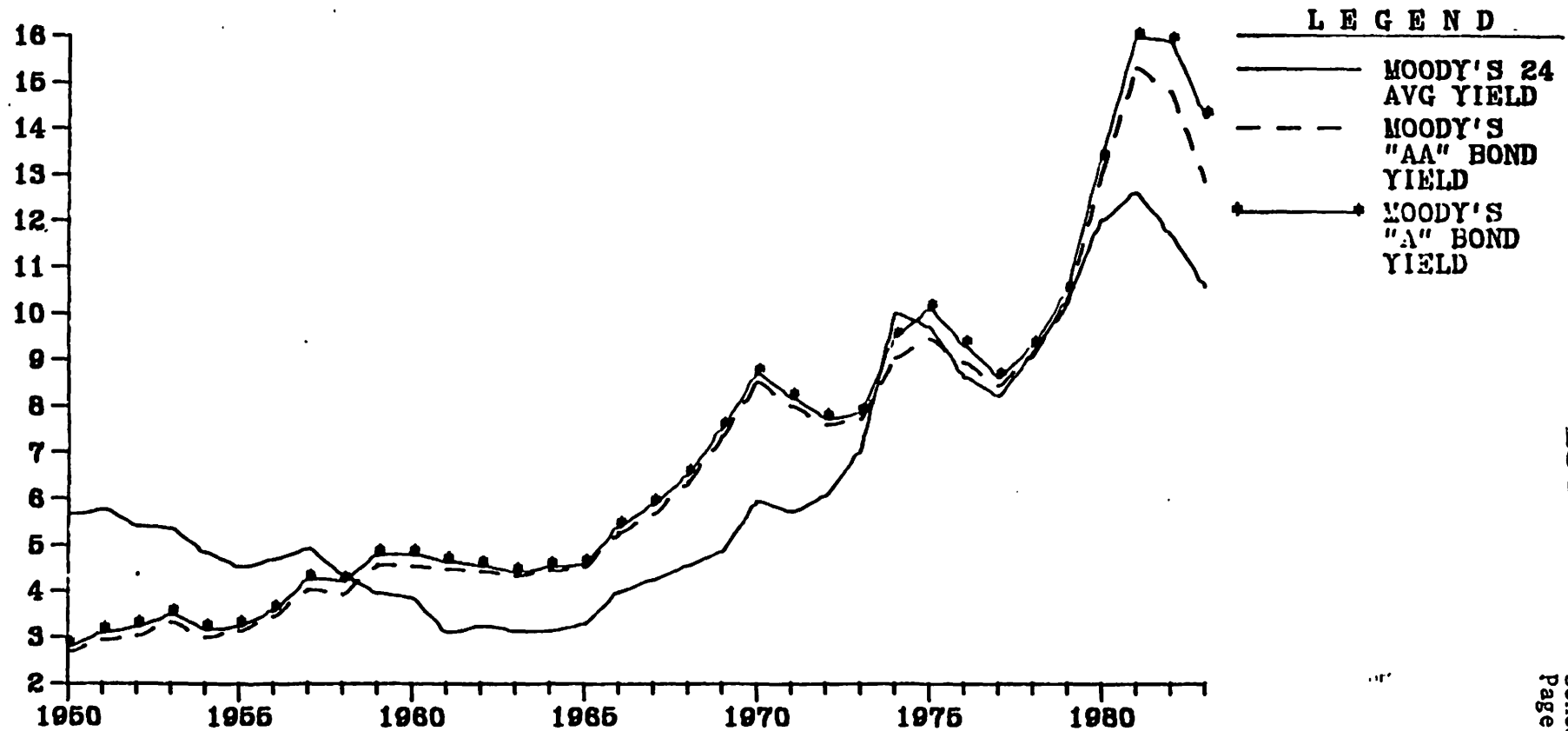
(**) HIGHEST CHANGE - 56.35%

AVERAGE CHANGE - 15.28%



BOND YIELD AVERAGES COMPARISON

TO
MOODY'S UTILITY COMMON STOCK YIELDS
1950 - FEBRUARY 1983



COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

990420318

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AT RICHMOND, APRIL 22, 1983

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY

To revise its tariffs

CASE NO. PUE830029

INTERIM ORDER

On March 31, 1983, Virginia Electric and Power Company ("Vepco" or "Company") filed with the Commission an application for an increase in annual revenues of \$175.2 million, to take effect in two steps. The proposed first step is an increase of \$44 million, which Company requests be allowed to go into effect on May 1, 1983, subject to refund. In its proposed second step, Company requests an additional increase of \$131.2 million, effective August 29, 1983.

The application states that the first step increase is consistent with existing Commission practice for expedited rate cases. The proposed expedited increase represents an increase in base rates of approximately 3.87%, which is equivalent to the increase in the Consumer Price Index in 1982. Company asserts that the first step increase is necessary in order to reduce the deficiency in Company's earnings from its Virginia jurisdictional business, based on its last authorized rate of return and the adjusted 1982 test year. The second step of the requested increase is designed to recover the remainder of the adjusted test

period revenue deficiency and to provide revenues to reflect an increase in Company's cost of equity capital. Additionally, the second step of the increase seeks revenues for a number of enumerated items, including (1) recovery of the investment in the cancelled nuclear unit, North Anna Unit 3, and a return on the investment in that unit while it is being written off, (2) recognition of a change in the Virginia jurisdictional allocation factor as a result of the loss of load of Company's North Carolina municipal customers, (3) allowance for synchronization of pro forma interest costs for federal income tax purposes, and (4) the continued gradual elimination of Allowance for Funds Used During Construction (AFUDC) and recognition of the elimination of the test period AFUDC associated with the portion of the Bath County project sold to the Allegheny Power System.

Company proposes to spread the first increase equally among its various classes of customers on an interim basis. It has requested that, after the hearing on the application, the total \$175.2 million be distributed in a manner which would move the returns from the various classes toward Company's overall rate of return. In order to accomplish this goal, Company proposes to increase the base rates of the residential class by 11.99%, while increasing the base rates of all other customer classes by approximately 9.81%.

Company has proposed changes to its rules and regulations governing master metering and submetering which are characterized as clarifying in nature. Company has also proposed changes in its charges for both overhead and underground temporary electric service.

The Commission has reviewed Company's application, together with its prefiled testimony and exhibits, and has reached specific conclusions regarding certain of Company's proposals.

1. With respect to the cancellation of North Anna Unit 3, we are confronted with the magnitude of the proposed write-off and its impact upon Virginia ratepayers. Company seeks to recover from its jurisdictional customers over a ten year period approximately \$240.7 million of construction and cancellation charges, net of salvage and tax credits. When adjusted for a proposed return on the uncollected cancellation costs to be collected during the write-off period, Vepco estimates the total cost to Virginia ratepayers over the ten year period to approximate \$649.1 million.

The magnitude of this write-off is unparalleled in Virginia. If it is not the largest write-off for a single, privately-owned nuclear unit in the nation, it is certainly one of the largest. The cancellation of this unit is not a "first" for Vepco; it is the fourth nuclear unit cancelled by Vepco in the past five years. The total revenue requirements associated with the three prior cancellations for which rate relief has been granted in Virginia equals approximately \$190 million and, when coupled with Company's current request, would drive the total cost to Virginia ratepayers for these abandoned nuclear units to more than \$839 million. We conclude that the sheer size of this write-off demands that we provide a review period longer than will be required to consider the usual rate-making aspects of the application.

Further, Company's evidence provides us with no independent basis for determining how much of these costs Company is entitled to recover. The testimony on this issue is brief and conclusory in nature. Vepco did not provide any of the studies alluded to in the testimony which allegedly support the conclusions of their witnesses. Nor has Company filed any of the data necessary to validate the assumptions and findings contained in such studies. We further find Company has paid scant attention to at least two critical issues raised by the cancellation, namely: the economic justification for the transfer of assets from North Anna Unit 3 to other nuclear units and why North Anna Unit 3 should not have been cancelled sooner - as was North Anna Unit 4, for example.

The cancellation of North Anna Unit 3 must be carefully examined and we find that Company's prefiled testimony regarding same to be inadequate on its face. We further conclude that a sufficient time schedule must be established to allow the Staff and all interested parties to review all relevant issues and submit their findings and recommendations to the Commission. Accordingly, we conclude that all issues related to the cancellation of North Anna Unit 3 should be considered separately from this proceeding. Further, we will initiate a separate investigation of the appropriate ratemaking treatment for the cancellation of North Anna Unit 3. Company will be directed to submit all evidence and information it deems pertinent to all cancellation issues. We anticipate that this matter will be heard in December of this year.

2. Turning again to the application, Company seeks an increase in equity above the range of 15-15 1/2% which the Commission last prescribed for Vepco. In Vepco's last two cases, we established rates based on the low end of that range (15%) after evaluating the performance of Vepco's generating units. The Company asserts that a 16% return on equity is now warranted in light of current financial conditions and the recent performance of its generating units. We have reviewed the Company's testimony on these issues and determined that no increase in the authorized equity return is warranted.

We are aware that since we last prescribed an equity return for Vepco, various factors which influence its cost of capital have improved. Inflation has abated. Interest rates have dropped significantly; in fact, Vepco's testimony indicates that its embedded cost of senior capital has declined since the last case. During the same time, the financial condition of Vepco has improved. We also note that the range of 15-15 1/2% falls within the range of returns established by the discounted cash flow analysis included in Vepco's prefiled testimony. Considering these factors, as well as the Commission's own knowledge of the cost of capital, we find that a change in the return on equity is not justified.

We have also examined Company's evidence pertaining to generating unit performance and find that the test year performance does not merit an increase in the equity return. While, in the aggregate, the performance of the major fossil

units has improved, we do not consider the level of performance during the test period as adequate to justify a reward. Most importantly, we note that during the test period the weighted average capacity factors of the units with the lowest production cost, i.e., the nuclear units, actually decreased from the prior year, with two of the units registering capacity factors of only 32% and 52%. We do not consider such levels of performance to be good. When the overall performance of Vepco's units are compared with the performance of other utilities in Virginia, such as Appalachian Power Company, we can only conclude that generating unit performance provides no basis for granting the Company an increase in equity return. Accordingly, we have determined that a return on equity of 15% shall be used to establish revenue requirements in this proceeding.

3. It is the Commission's policy to allow an expedited increase... i.e. within thirty days of filing... only when the proposed increase conforms to all conditions of our present guidelines, including the CPI limitation on the amount of additional revenues allowable. Since the total requested increase of \$175.2 million would produce additional annual revenues in excess of the CPI limitation, we find that the Company's proposed first step increase should be denied.

NOW, THEREFORE, THE COMMISSION, having considered the application, is of the opinion and hereby finds:

(1) That Vepco's request for an interim increase in rates shall be denied;

(2) That no further consideration shall be given in this proceeding to any revenue needs of Company which are attributable to the cancellation of North Anna Unit 3, and that Company shall be directed to respond to a separate, independent investigation by this Commission into all matters and issues pertaining to said cancellation;

(3) That Company's request for an increased return on equity shall be denied and that Company's currently authorized return on equity is just and reasonable;

(4) That all proposed rates, tolls, and charges unrelated to the cancellation of North Anna Unit 3 and the increased equity return shall be suspended for the statutory period prescribed in §56-238 of the Code of Virginia;

(5) That members of the Commission's Staff shall investigate Company's application and the reasonableness of all tariff changes related to the application, as modified by our actions herein, and present their findings to the Commission; and

(6) That a public hearing shall be scheduled before a Hearing Examiner to receive evidence relevant to all matters arising from Company's application not disposed of by this order. Accordingly,

IT IS ORDERED:

(1) That all revenue requirements associated with the cancellation of North Anna Unit 3 and the increase in equity return are denied;

(2) That on or before April 29, 1983, Company shall file revised schedules, exhibits, and tariffs to reflect the Commission's findings on return on equity and the cancellation of North Anna Unit 3 and such revised schedules and exhibits shall remove all revenue requirements associated with the proposed amortization of the write-off, the proposed rate base treatment of the write-off, the proposed elimination of the test period AFUDC related to North Anna Unit 3, and the requested increase in the authorized return on equity;

(3) That enforcement of all proposed tariff changes, as modified by the findings herein, be, and they hereby are, suspended for a period of one hundred fifty (150) days from the date the application was filed to and through August 28, 1983;

(4) That a public hearing for the purpose of receiving evidence relevant to Company's application be held commencing on July 19, 1983, at 10:00 a.m. in the Commission's Courtroom, 13th Floor, Jefferson Building;

(5) That, in accordance with §12.1-31 of the Code of Virginia, a Hearing Examiner shall conduct all further proceedings in this matter on behalf of the Commission, concluding with the filing of the Examiner's final report to the Commission. In the discharge of such duties, the Hearing Examiner shall exercise all the inquisitorial powers possessed by the Commission, including, but not limited to, the power to administer oaths, require the appearance of witnesses and parties and the production of documents,

schedule and conduct pre-hearing conferences, admit or exclude evidence, grant or deny continuances, and rule on motions, matters of law and procedural questions. Any party objecting to any ruling or action of said Examiner shall make known its objection with reasonable certainty at the time of the ruling, and may argue such objections to the Commission as a part of its responses to the final report of said Examiner; provided, however, if any ruling by the Examiner denies further participation by any party in interest in a proceeding not thereby concluded, such party shall have the right to file a written motion with the Examiner for his immediate certification of such ruling to the Commission for its consideration. Pending resolution by the Commission of any ruling so certified, the Examiner shall retain procedural control of the proceeding;

(6) That Company forthwith make copies of its application and prefiled testimony available for public inspection during regular business hours at all offices where customer bills may be paid;

(7) That, on or before May 25, 1983, any person who expects to submit evidence, cross-examine witnesses, and otherwise participate in the hearing as a Protestant as provided in Rule 4:6 of the Commission's Rules of Practice and Procedure, shall file with the Clerk, Document Control Center, P.O. Box 2118, Richmond, Virginia 23216, an original and twenty (20) copies of a Notice of Protest as provided by Rule 5:16(a) and shall serve a copy on Vepco. Service on Company shall be directed to: Evans B. Brasfield, Esquire, Hunton & Williams, P.O. Box 1535, Richmond, Virginia 23212;

(8) That, on or before June 30, 1983, each Protestant shall file an original and twenty (20) copies each of a Protest (SCC Rule 5:16(b)) and of the prepared testimony and exhibits Protestant intends to present at the public hearing, and serve five (5) copies of each upon Company;

(9) That, within 5 days of receipt of any Notice of Protest, Company shall serve on each Protestant a copy of all material now or hereinafter filed with the Commission;

(10) That, on or before June 30, 1983, the Commission Staff shall file an original and twenty (20) copies of the prepared testimony and exhibits Staff intends to present at the hearing and send a copy to Company and each Protestant;

(11) That, on or before July 11, 1983, Company shall file an original and twenty (20) copies of all testimony and exhibits it expects to introduce in rebuttal to the direct pre-filed testimony and exhibits of both Commission Staff and Protestants; additional rebuttal evidence may be presented by Company without pre-filing provided it is in response to evidence which was not pre-filed, but elicited at the time of hearing and, provided further, the need for additional rebuttal evidence is timely addressed by motion during the hearing and leave granted by the Hearing Examiner; a copy of the pre-filed rebuttal evidence shall be sent to all Protestants by Company;

(12) That Company will respond to written interrogatories within ten (10) business days after receipt of the interrogatories. Protestants will respond to written interrogatories of Company in three (3) days. Protestants will provide

Company with any work papers or documents used in preparation of their filed testimony promptly upon request. Except as modified above, discovery shall be in accordance with the Rules set forth in Part VI of the Commission's Rules of Practice and Procedure;

(13) That, on or before May 11, 1983, Company shall cause a copy of the following notice to be published as display advertising (not classified advertising) once a week for two (2) consecutive weeks in newspapers of general circulation throughout its service territory:

NOTICE TO THE PUBLIC OF A PROPOSED RATE
INCREASE BY VIRGINIA ELECTRIC AND POWER COMPANY

On March 31, 1983, Virginia Electric and Power Company ("Vepco" or "Company") filed with the Commission an application for an increase in annual revenues of \$175.2 million to take effect in two steps. The first step is an increase of \$44 million, which Company requests be allowed to go into effect subject to refund on May 1, 1983. As a second step, Company requests an additional increase of \$131.2 million to go into effect by August 29, 1983.

The Company proposes to spread the increase of \$175.2 million in a manner which would move the returns from the various classes toward the Company's overall rate of return. In order to accomplish this goal Company proposes to increase the base rates of the residential class by 11.99 percent while increasing the base rates of all other customer classes by approximately 9.81 percent.

Company has proposed changes to its rules and regulations governing master metering and submetering which it characterizes as clarifying in nature. Company has also proposed changes in its charges for both overhead and underground temporary electric service.

By order dated April 22, 1983, the Commission denied Vepco's request for an interim increase in rates and suspended the effectiveness of all proposed rates to and through August 28, 1983. The Commission has dismissed several issues raised in the application. First, it has denied Company's request for an increase on its equity return above the level established in Vepco's 1981 rate case. Second, it denied that portion of Company's application pertaining to the cancellation of North Anna Unit 3 and directed that the cancellation shall be considered in a separate, independent investigation by its Commission.

The Commission has scheduled a public hearing before a Hearing Examiner to begin at 10:00 a.m. on July 19, 1983, in the Commission's Courtroom, 13th Floor, Jefferson Building, Bank and Governor Streets, Richmond, Virginia to receive evidence relevant to the proposed rate increase.

Parties who wish to speak at the July 19, 1983 hearing and not participate as a Protestant, may be scheduled by writing the address listed in the last paragraph of this notice. Any person who wishes to comment in writing on the proposed increase should send such comment to the same address.

Copies of the application, the proposed schedules of rates and charges, the schedules and exhibits as revised in accordance with the Commission's April 22, 1983 order, and the testimony of Vepco's witnesses may be reviewed in the Document Control Center of the Commission or at any office of Vepco where bills may be paid.

On or before May 25, 1983, all persons who expect to submit evidence, cross-examine witnesses, and otherwise participate in the hearing as Protestants, as provided by Rule 4:6 of the Commission's Rules of Practice and Procedure, shall file with the Clerk a Notice of Protest as required by Rule 5:16(a). A copy of the Notice of Protest shall be served on Company's counsel, Evans B. Brasfield, Esquire, Hunton & Williams, P.O. Box 1535, Richmond, Virginia 23212.

On or before June 30, 1983, the Commission's Staff shall file with the Clerk the prepared testimony and exhibits of each witness expected to present direct testimony and shall serve a copy upon Company's counsel and each Protestant.

On or before June 30, 1983, all persons who have filed a Notice of Protest and who still expect to participate at the hearing as a party Protestant must file an original and twenty (20) copies of all prepared testimony and exhibits of the witnesses to be offered at the hearing and shall serve five (5) copies thereof upon counsel for Company and upon all other Protestants. No later than June 30, 1983, all Protestants shall also have filed a written Protest as required by Commission Rule 5:16(b).

On or before July 11, 1983, Company shall file with the Clerk and each Protestant the testimony and exhibits it expects to introduce in rebuttal to the direct prefiled testimony and exhibits of the Commission Staff and the Protestants.

Any party participating as a Protestant should review the instructions regarding discovery set forth in the Commission's order in this proceeding dated April 22, 1983.

All written communications and filings pertaining to the application should be addressed to Clerk, Document Control Center, P.O. Box 2118, Richmond, Virginia 23216.

VIRGINIA ELECTRIC AND POWER COMPANY

(14) That on or before May 11, 1983, Company serve a copy of this order and its application on the Commonwealth's Attorney and Chairman of the Board of Supervisors of each county (or equivalent officials in counties having alternate forms of government) in which Company offers service, and on

the Mayor or Manager of every city and town (or on equivalent officials in towns and cities having alternate forms of government) in which Company offers service. Service shall be made by personal delivery to the customary place of business of the person served, or to his residence, or shall be sent by certified mail, return receipt requested; and

(15) That, at the commencement of the hearing scheduled herein, Company provide the Commission with proof of notice and service on local officials.

BRADSHAW, Commissioner, dissents.

The simple fundamental that must be emphasized is that basic fairness dictates that all evidence received into the record by the Commission or relied upon by the Commission in making its decision must be disclosed to all the parties for examination and comment. The Commission cannot simply summarily apply its expertise and fix a rate of return. Stockholders, given the opportunity of a hearing, could possibly bolster the Company's request or intervenors given the opportunity of a hearing, could possibly submit credible evidence to lower the Commission's fixed rate of return. Though I might agree with the conclusion my colleagues have reached, I do not agree that a paramount issue such as the authorized rate of return raised by the Company's filing should be summarily denied -- to do so I respectfully submit is a violation of due process to both the applicant and intervenors.

Further, all issues before us are in the context of a rate case. Virginia Code §56-238 permits the proposed rates, tolls, and charges to go in effect, as filed for, subject to refund, at the expiration of 150 days (August 29, 1983). To carve out of the rate case a single issue (recovery of the investment in the cancelled nuclear unit) and set for a separate hearing beyond the expiration of 150 days, in my opinion, imposes an unnecessary risk of higher rates upon the customers at the Company's option. Being fully cognizant of the magnitude of the cancellation issue, which the legislature may not have anticipated when enacting §56-238, not to decide within 150 days I view as a breach of the statutory restraint imposed by this provision. I do not believe this restraint is avoided by denying the revenue requirements associated with the cancellation (ordering paragraph 1) and setting an independent hearing later. If the final cancellation decision came after December 31, 1983, the majority could be imposing an unnecessary risk upon the earnings of the Company for the year 1983. The Company accountants closing the books at year end are confronted with only one certainty - a denial of these costs for the year 1983.


Lastly, I fear the precedent for all future rate cases this order establishes.

ATTESTED COPIES hereof shall be sent to Evans B. Brasfield, Esquire, Hunton & Williams, P.O. Box 1535, Richmond, Virginia 23212; Anthony Gambardella, Esquire, Office of the Attorney

General, Division of Consumer Counsel, 101 North 8th Street,
5th Floor, Richmond, Virginia 23219; and to the Commission's
Divisions of Energy Regulation, Accounting and Finance,
and Economic Research and Development.

A True Copy

Teste:

A handwritten signature in cursive script, reading "William C. Young".

Clerk of State Corporation Commission

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

Application of)
)
VIRGINIA ELECTRIC AND POWER COMPANY) CASE NO. PUE830029

Petition for Reconsideration

Virginia Electric and Power Company (Vepco, the Company) hereby petitions the Commission, pursuant to Rule 7:9 of the Commission's Rule of Practice and Procedure, to reconsider its "Interim Order" of April 22, 1983 (the Order), and in support thereof states as follows:

1. The Commission summarily denied the Company needed relief in three areas:
 - a. It denied the Company's request for an increase in the allowed rate of return on equity;
 - b. It made a final determination prohibiting any rate relief in this case resulting from the cancellation of North Anna Unit 3 and the elimination of the investment therein from rate base; and
 - c. Having confirmed the exclusion of the North Anna 3 investment from rate base, it required the inclusion in this case of Allowance for Funds Used During Construction (AFUDC) relating to such investment.

In each instance the Company was given no opportunity to be heard on these issues, and no opportunity to respond to the assertions on which the Commission's summary disposition is based. The

result is not only denial of major components of the Company's request, reducing the requested amount by some \$120 million, but also a reduction in present rates of \$54.7 million.

2. By requiring a separate investigation and hearing in December 1983 on the appropriate ratemaking treatment for the cancellation of North Anna Unit 3, the Order deprives the Company, without a hearing, of a valuable right given to it by statute: the right to recover, subject to refund, the revenue requirement attributable to the cancellation of North Anna Unit 3 from August 29, 1983 to some remote date in 1984 when the separate proceeding can be concluded.

3. The separation of the North Anna Unit 3 cancellation into a separate proceeding also has the effect of requiring, without a hearing, a reduction in present rates. Those rates include a revenue requirement of \$28 million based on North Anna Unit 3 being in rate base. By removing North Anna 3 from the rates entirely, the Commission requires a rate reduction of \$28 million.

4. In addition, the Commission's treatment of the North Anna Unit 3 AFUDC is inconsistent with its rate base treatment of that unit and requires a further reduction in present rates. The Order requires the Company to "remove all revenue requirements associated with. . .the proposed elimination of the test period AFUDC related to North Anna Unit 3." That would be appropriate if North Anna Unit 3 were in rate base, but that is not the case. Because of the cancellation, North Anna Unit 3 has been excluded from the year-end 1982 rate base. Since AFUDC is an offset to

Construction Work in Progress (CWIP) in the rate base, the AFUDC attributable to CWIP removed from the rate base must likewise be removed. By ordering the restoration of the AFUDC related to the North Anna 3 CWIP, when that CWIP is no longer in the rate base, the Commission improperly excludes one-half of the AFUDC-CWIP equation. The decision on this point implies that AFUDC will continue to accrue in 1983, and that clearly is not the case. This requirement, taken alone, causes a \$26.7 million further reduction in present rates. The total reduction in present rates that the Commission's order requires is, therefore, \$54.7 million.

5. These actions by the Commission violate the governing statute. Section 56-238 of the Code of Virginia provides:

The Commission. . .may suspend the enforcement of any or all of the proposed rates. . .for a period not exceeding one hundred fifty days from the date of the filing, during which time it shall investigate the reasonableness or justice of the proposed rates. . .and thereupon fix and order substituted therefore such rates. . .as shall be just and reasonable.

Under this statute the Commission has only the power to suspend; it has no power to deny at the time of filing, and its duty is to investigate during the suspension period and then substitute rates it deems proper. In its summary treatment of rate of return on common equity, the cancellation of North Anna Unit 3 and the AFUDC attributable to North Anna Unit 3, the Commission has failed to comply with the statute and its action exceeds its authority.

6. In addition, by taking such action without giving the Company an opportunity to be heard, the Commission deprived the Company of due process of law. Railroad Comm'n. v. Pacific Gas & Electric Co., 302 U.S. 388, 393 (1938); Ohio Bell Tel. Co. v. Public Utilities Comm'n., 301, U.S. 292, 300 (1937); see Commonwealth v. Virginia Electric and Power Company, 211 Va. 758, 772 (1971); Norfolk v. Virginia Electric and Power Company, 197 Va. 505, 518 (1955); Chesapeake & Potomac Tel. Co. v. Commonwealth, 147 Va. 43, 53 (1927).

7. The Order makes final disposition of these issues in that it is a final determination as to the rate of return on common equity, as to the Company's ability to recover revenues attributable to North Anna 3 subject to refund, and as to the requirement to reduce present rates on August 29, 1983 by reason of the removal from this proceeding of the North Anna 3 issues. In the absence of reconsideration or suspension pending appeal, the Company will, under the Order, be permanently deprived of revenues related to these issues.

8. The summary and unlawful action by the Commission is very damaging to the Company and is contrary to the interest of its customers. The removal of the North Anna Unit 3 cancellation from this proceeding, the denial to the Company of its right to recover, subject to refund, revenues related to that cancellation and the ratemaking treatment imposed with respect to the North Anna 3 AFUDC all create substantial uncertainty as to when and whether a North Anna 3 write off will be allowed and whether the Company will be able to finance the replacement capacity for the

canceled unit. Vepco's capital requirements for 1983 are \$815 million, and the Company had proposed to raise \$150 million of this with a mortgage bond offering in June. The Commission's Order has created such uncertainty concerning the North Anna 3 write off and the Company's prospects generally that it appears inadvisable to make such an offering. Under these circumstances, if short-term debt is to be kept to a reasonable level, it will be necessary to make substantial reductions in the Company's cash requirements, and the Company, in the exercise of prudent financial management, must take the following steps:

- a. Avoidance of commitments with neighboring utilities for generating capacity to replace the North Anna Unit 3 capacity. Some of those utilities have indicated that continued construction of their capacity will be dependent upon an early commitment from Vepco, so any significant delay may mean that economical capacity will be lost.
- b. An immediate freeze on all hiring.
- c. A reduction of fuel inventories to a point that will permit continuous operations under normal conditions but will provide inadequate reserve margins for emergencies.
- d. Attempt to arrange interim financing. The uncertainties created by the Order will likely necessitate that a premium be paid for such financing.

9. In addition, if reconsideration, or suspension pending appeal, of the Commission's Order is not obtained, it will be necessary to make significant reductions in the Company's capital improvement program in order to conserve cash. This will have an adverse impact on future costs and the economy of the Commonwealth.

10. These harmful consequences can be avoided only if the Commission gives favorable reconsideration to its Order of April 22, 1983.

11. The Commission's news release in connection with the Order described the Commission's action as "extraordinary". In view of its extraordinary character, and the extraordinary damages that may result from the uncertainty it creates, the Company requests the Commission to make exception to the provision of Rule 7:9 that prohibits oral argument on petitions for reconsideration and asks leave to present oral argument on this Petition.

WHEREFORE, the Company requests the Commission to reconsider its Order and to enter an amending order allowing all issues presented by the Company's Application to be considered in a timely fashion at an appropriate hearing and, if the decision has not been made by August 29, to allow rates to go into effect subject to refund in accordance with § 56-238 of the Code of Virginia. The Company further requests that the Commission suspend the Order, pursuant to Rule 7:9, pending action on this Petition.

April 27, 1983

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By Evans B. Brasfield

John W. Riely, Esq.
Evans B. Brasfield, Esq.
Richard D. Gary, Esq.
Patricia M. Schwarzschild, Esq.
Hunton & Williams
P. O. Box 1535
Richmond, Virginia 23212

Counsel

Certificate

I certify that on April 27, 1983 a copy of the foregoing Petition was mailed or delivered to A. C. Epps, Esq., Christian, Barton, Epps, Brent & Chappell, 1200 Mutual Building, Richmond, Virginia 23219, counsel for the Virginia Committee for Fair Utility Rates; Anthony Gambardella, Esq., Assistant Attorney General, 101 North Eighth Street, Richmond, Virginia 23219; and Kenworth E. Lion, Jr., Esq., Assistant General Counsel, State Corporation Commission, P. O. Box 1197, Richmond, Virginia 23209.

Evans B. Brasfield

NOTED MAY 3 1983 V.A.S. cc 214 E. B. BRASFIELD ESQ
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AT RICHMOND, APRIL 29, 1983

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUE830029

To revise its tariffs

ORDER SUSPENDING FILING DATE

Ordering paragraph (2) in the April 22, 1983 Interim Order in this proceeding required Company to file revised schedules, exhibits, and tariffs on or before April 29, 1983, to reflect the Commission's findings in said order on return on equity and the cancellation of North Anna Unit 3. On April 27, 1983, Company filed a Petition for Reconsideration of the Commission's Interim Order.

The Commission is of the opinion and hereby finds that the aforementioned filing requirement should be suspended until further order of the Commission. Accordingly,

IT IS ORDERED

That the requirement to file revised schedules, exhibits, and tariffs contained in ordering paragraph (2) of the Commission's April 22, 1983 Interim Order be, and same hereby is, suspended until further order of the Commission.

ATTESTED COPIES hereof shall be sent to Evans B. Brasfield, Esquire, Hunton and Williams, P.O. Box 1535, Richmond, Virginia 23212; Anthony Gambardella, Esquire, Office of the Attorney General, Division of Consumer Counsel, 101 North 8th Street, 5th Floor, Richmond, Virginia 23219; and to the Commission's Divisions of Energy Regulation, Accounting and Finance and Economic Research and Development.

A True Copy
Teste:

George W. Bryant Jr.
First Assistant Clerk of the
State Corporation Commission

MAY 13

AT RICHMOND, MAY 13, 1983

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY

To revise its tariffs

CASE NO. PUE830029

ORDER DISPOSING OF PETITION FOR RECONSIDERATION

On March 31, 1983, Virginia Electric and Power Company ("Vepco" or "Company") filed with the Commission an application for an increase in annual revenues of \$175.2 million. By Interim Order entered April 22, 1983, the Commission, inter alia, denied all revenue requirements associated with the cancellation of North Anna Unit 3 as well as the proposed increase in equity return. Both denials were predicated upon the record presented by Vepco, and the order specifically anticipates a full, separate investigation into the cancellation costs associated with North Anna Unit 3, together with a public hearing in December, which will afford Company and the public full opportunity to develop a record which will support a fair disposition of the issues. All revenue requirements not disposed of by the prior order of April 22 were to be considered in usual rate case fashion, including a public hearing scheduled for July 19, 1983.

On April 27, 1983, Company filed a Petition for Reconsideration, requesting the Commission to reconsider its Interim Order, to enter an amending order allowing all issues presented by Company's application to be considered in one hearing, and to allow the Company's proposed rates to become effective August 29, 1983, subject to refund if a final decision has not been made by that time.

The Commission, having reconsidered its prior order, for reasons hereinafter stated, is of the opinion that the proper test year treatment of the AFUDC related to North Anna CWIP should be addressed in the rate hearing scheduled for July 19, as opposed to the subsequent hearing anticipated during December. Otherwise, the Commission is of the opinion that the relief sought by the Petition for Reconsideration should be denied.

Since Company's Petition for Reconsideration makes very specific allegations which we find to be either factually incorrect or improper conclusions of law, we think it timely to denote at least the major issues raised with which we differ.

The Company contends that our earlier denial of its requested increase in equity return and our denial of its requested cost recovery associated with the cancellation of North Anna Unit 3 were determined without Company's having an opportunity to be heard -- in violation of due process of law. To the contrary, when its application was filed, Company was expected to present its best case, together with all supporting data. Under formally adopted SCC rules, Vepco is required to prefile all testimony and exhibits by which Company expected to establish its case. Vepco purported to comply with these rules and prefiled its evidence.

The Commission carefully reviewed all supporting evidence filed by Vepco in this proceeding -- on all issues. We studied the relatively voluminous submissions on the equity return request and were not convinced by the Company's conclusions

and contentions with regard thereto. We scrutinized the record compiled by Vepco seeking appropriate support for its request for approximately \$649.1 million over the next ten years to compensate Company for its investment in North Anna Unit 3, which was cancelled on November 19, 1982. As for the latter, a scant sixteen, inconsecutive pages of testimony -- consisting primarily of subjective conclusions -- provided no rational basis for the regulatory action which was requested. We realize the importance of addressing the cancellation issues as expeditiously as possible and, for that reason, after denying any relief on the woefully inadequate evidence offered by the Company, we directed an immediate investigation of the cancellation costs -- to be culminated in a public hearing to be conducted as promptly as a thorough investigation permits.

Nor do we find persuasive the contention that we have denied other parties the right to be heard. Our order was directed solely to Company. It does not preclude future interveners or protestants from challenging, during the hearings to follow, any aspect of Vepco's present or proposed rate changes. Of course, Company will have full opportunity to respond to all evidence presented at those hearings.

Company further contends that Virginia Code §56-238 was violated by our action denying the cancellation relief sought by its application. Company again ignores the fact that it prefiled the information it was relying upon to support its request. That information was reviewed by the Commission and was determined to be totally insufficient. Accordingly, the proposed revised tariffs were denied. When a public utility fails to support an application as it is

required to do, the Commission is not limited by Code §56-238 solely to the power to suspend the proposed tariffs. As was done here, the Commission can review the Company's supporting evidence and dispose of proposals not supported by a sufficiency of evidence.

Company states that the Interim Order requires a reduction in present rates. Ordering paragraph (2) of our April 22 order required Company to file revised, proposed tariffs, not to reduce present tariffs. The Interim Order merely reduced the potential amount of any increase which might result from the July proceeding. Assuming that Company can fully justify the various components of the application, the Commission's Interim Order would have afforded Company the opportunity for an increase in annual revenues of nearly \$56 million. Whether the present tariffs will be increased or decreased is something that will only be known after that hearing is concluded.

Company has stated that the Commission's Interim Order has created "substantial uncertainty as to when and whether a North Anna 3 write off will be allowed and whether the Company will be able to finance the replacement capacity for the canceled unit." Additionally, Company expressed an intention to take certain austerity measures.

We find no merit to its claim that the prior order has in fact created any uncertainty regarding cancellation recovery. In the Interim Order, the Commission determined that it will consider the cancellation issue in a separate, independent proceeding. We fail to see how such action has in any way created uncertainty regarding final disposition upon a full and proper record.

As above stated, we have concluded that one issue which was slated to be heard in December can fairly be considered at the July hearing, namely, the treatment of AFUDC booked during the test year on plant no longer in Company's rate base. Our order of April 22, 1983, required that, for the purposes of the July proceeding, the test year should reflect the AFUDC booked on North Anna Unit 3. In directing that action, we followed the treatment afforded a similar item in Vepco's earlier cancellation of North Anna Unit 4. However, that treatment of the issue was not regarded as settled. We are also confronted with a like issue with respect to the test period AFUDC on the portion of the Bath County unit sold during the test year. Since the latter is to be heard as part of the July proceeding, we conclude that it would then be appropriate to hear and determine the total AFUDC (including that related to North Anna Unit 3) which should be used for setting future rates. The effect of this decision is to increase the potential increase in annual revenues to be considered in the July hearing from approximately \$55.6 million to approximately \$82.3 million and to decrease the amount to be considered at the latter hearing from approximately \$91.5 million to approximately \$64.8 million.

IT IS ORDERED that the relief sought in Company's Petition for Reconsideration be, and same hereby is, denied except to the extent that the AFUDC associated with North Anna Unit 3 will be considered at the July hearing. Company shall file revised schedules, exhibits, and tariffs to reflect the decision herein.

JUDGE BRADSHAW, dissenting, with opinion to be filed subsequently.

ATTESTED COPIES hereof shall be sent to Evans B. Brasfield, Esquire, Hunton & Williams, P.O. Box 1535, Richmond, Virginia 23212; Anthony Gambardella, Esquire, Office of the Attorney General, Division of Consumer Counsel, 101 North 8th Street, 5th Floor, Richmond, Virginia 23219; and to the Commission's Divisions of Energy Regulation, Accounting and Finance, and Economic Research and Development.

A True Copy
Teste:

George W. Bryant Jr.
First Assistant Clerk of the
State Corporation Commission

COMMONWEALTH OF VIRGINIA
DOCUMENT CONTROL CENTER - RATE CORPORATION COMMISSION.

AT RICHMOND, MAY 20, 1983

MAY 20 2 57 PM '83

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY

To revise its tariffs

CASE NO. PUE830029

BRADSHAW, Commissioner, dissents.

By Order dated April 22, 1983, the Commission without a hearing determined Vepco's rate of return from the Company's filed testimony, divorced a major issue from Vepco's rate case and set this matter for a separate hearing later this year. I dissented in this Order. On April 27, 1983, Vepco filed for reconsideration of the April 22nd Order. On May 13, 1983, the Commission by Order denied reconsideration.

This Order denying reconsideration, in my opinion, compounds an original error and makes the lack of due process more glaring. Vepco's evidence on equity return is denied without a hearing even though other parties may come in later or be heard on the same issue. This is not basically fair and does not meet due process standards. Had the reverse occurred -- if the Commission had granted Vepco's rate of return as filed without a hearing I am certain legislators, intervenors and the general public would have legitimately charged that such action was not fair and did not meet due process standards. Due process is a two-way street.

The Commission's action is an obvious attempt to avoid a clear legislative mandate -- namely, to decide rate cases within 150 days or let the new rates go into effect subject to refund. This law is rendered useless if the Commission can simply deny a request within a 150 day period, then set it for further investigation and hearing beyond the 150 day period.

ATTESTED COPIES hereof shall be sent to Evans B. Brasfield, Esquire, Hunton & Williams, P. O. Box 1535, Richmond, Virginia 23212; Anthony Gambardella, Esquire, Office of the Attorney General, Division of Consumer Counsel, 101 North 8th Street, 5th Floor, Richmond, Virginia 23219; and to the Commission's Divisions of Energy Regulation, Accounting and Finance, and Economic Research and Development.

A True Copy
Teste:

George W. Bryant Jr.

First Assistant Clerk of the
State Corporation Commission

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

Application of)	
)	
VIRGINIA ELECTRIC AND)	CASE No. PUE830029
POWER COMPANY)	

Motion for Suspension

Virginia Electric and Power Company (the Company) moves the Commission, pursuant to § 8.01-676F of the Code of Virginia, to suspend, pending decision by the Supreme Court of Virginia of the Company's appeal, the provisions of the Interim Order entered April 22, 1983 and the Order Disposing of Petition for Reconsideration entered May 13, 1983 that required removal from this case of the revenue requirements associated with North Anna Unit 3.

One of the questions that the Company will raise on appeal is the legality of the Commission's action with respect to the North Anna Unit 3 revenue requirements, and it is the Company's position that the Commission's action deprived it unlawfully of the right, under § 56-238 of the Code of Virginia, to recover those revenue requirements pending the Commission's ultimate resolution of the North Anna issue in a separate proceeding. If the Company's position on this issue is ultimately sustained, and if the Commission's orders in this regard are not suspended, the Company will be irreparably injured by the loss of revenues from

August 29, 1983 until the date as of which the Commission ultimately decides the North Anna 3 issue and rates reflecting this decision are placed into effect. If suspension is granted, however, the Company will not be required to suffer this loss and customers will be protected from any loss by the Company's refund obligation under § 56-238 and the requirement of a suspending bond under § 8.01-676F. This Motion for Suspension is not intended to request that the North Anna 3 issue be heard in the hearing now scheduled in July, but rather to request only that the North Anna 3 revenue requirements be subject, pending ultimate resolution of the issue, to the 150 day limit on suspension provided by § 56-238.

May 23, 1983

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By


Counsel

John W. Riely
Evans B. Brasfield
Richard D. Gary
Patricia M. Schwarzschild
HUNTON & WILLIAMS
P. O. Box 1535
Richmond, Virginia 23212

Counsel

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

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AT RICHMOND, JUNE 24, 1983

APPLICATION OF

VIRGINIA ELECTRIC & POWER COMPANY

CASE NO. PUE830029

To revise its tariffs

ORDER DENYING MOTION FOR SUSPENSION

Virginia Electric & Power Company ("Vepco"), pursuant to Virginia Code §8.01-676F, on May 23, 1983, moved the Commission to suspend, in part, two prior orders entered in the case, pending decision of their appeal. Suspension is requested of the Interim Order entered April 22, 1983, and of the Order Disposing of Petition for Reconsideration entered May 13, 1983, only to the extent that said order dismissed from the present case all consideration of revenue requirements associated with Vepco's cancellation of its North Anna Unit 3 nuclear generating facility.

The Commission, having considered the Motion to suspend, is of the opinion, and so finds, that such suspension would be contrary to the proper administration of justice in this case. Accordingly, it is hereby ORDERED that Vepco's Motion for Suspension be, and same hereby is, denied.

ATTESTED COPIES hereof shall be sent to: Evans B. Brasfield, Esquire, Hunton & Williams, P. O. Box 1535, Richmond, Virginia 23212; Charles F. Midkiff, Esquire, Christian, Barton, Epps, Brent & Chappell, 1200 Mutual Building, Richmond, Virginia 23219; Fritz Wiecking, Nine

West Main Street, Richmond, Virginia 23220; Richard A. Golden, Esquire, Assistant County Attorney, 4100 Chain Bridge Road, Fairfax, Virginia 22030; Frann G. Francis, Esquire, Apartment & Office Bulding Association of Metropolitan Washington, Inc., 1413 K Street, N.W., Suite 600, Washington, D.C. 20005; Edward L. Flippen, Esquire, Mays, Valentine, Davenport & Moore, P. O. Box 1122, Richmond, Virginia 23208; Kathee Myers, c/o Campus Center, College of William & Mary, Williamsburg, Virginia 23185; Anthony Gambardella, Esquire, Office of the Attorney General, Division of Consumer Counsel, 101 North Eighth Street, Fifth Floor, Richmond, Virginia 23219; and to the Commission's Division of Energy Regulation, Accounting and Finance, and Economic Research and Development.

A True Copy
Teste:

George H. Bryant Jr.

First Assistant Clerk of the
State Corporation Commission

IN THE
SUPREME COURT OF VIRGINIA
AT RICHMOND

Record No. _____

VIRGINIA ELECTRIC AND POWER COMPANY,
Appellant

v.

STATE CORPORATION COMMISSION,
Appellee.

PETITION FOR APPEAL AND SUSPENSION
AND MOTION FOR EXPEDITED APPEAL

Virginia Electric and Power Company (the Company), pursuant to Rule 5:18(g) of the Rules of the Supreme Court of Virginia, hereby (a) petitions for appeal from certain provisions of the "Interim Order" entered by the State Corporation Commission (the Commission) on April 22, 1983 and the "Order Disposing of Petition for Reconsideration" entered by the Commission on May 13, 1983 (the Orders), (b) applies to the Court, pursuant to § 8.01-676F of the Code of Virginia, to suspend, pending decision by the Court of the Company's appeal, those provisions, and (c) moves the Court to expedite this appeal, stating in support thereof as follows:

1. On March 31, 1983, the Company filed with the Commission its Application for an Increase in Rates, in which it requested the Commission to approve an increase in electric rates of \$175 million (on an annual basis) in two steps: \$44 million

to go into effect subject to refund on May 1, 1983, pursuant to § 56-240 of the Code of Virginia (Step 1), and \$131 million to be suspended pursuant to § 56-238 of the Code of Virginia and, unless the Commission had concluded its investigation and entered its final order prior thereto, to take effect subject to refund on August 29, 1983 (Step 2).¹ The \$175 million increase requested included, among other things, revenues based on a proposed increase in the approved rate of return on equity (\$28 million on an annual basis) and revenues based on the Company's proposed ratemaking treatment of the cancellation of North Anna Unit 3, a nuclear generating unit that had been under construction until cancelled in November of 1982 (\$37 million on an annual basis).

¹The procedure for ratemaking in Virginia is basically simple. A public utility is obligated to furnish adequate service at reasonable and just rates. Va. Code § 56-234. If the Commission determines after hearing that rates are not reasonable and just, it may prescribe reasonable and just rates. Va. Code § 56-235. Changes in rates by the utility require thirty days advance notice to the Commission and to customers. Va. Code § 56-237. If the rates filed when such notice is given are not suspended, they become effective at the end of the notice period on the date stated therein. But the Commission may suspend the enforcement of "any or all of the proposed rates" for up to 150 days. Va. Code § 56-238. It is to be noted that it is during this period of suspension that the Commission must investigate the reasonableness and justness of the proposed rates. If a decision is not reached during the 150 days, the utility, upon expiration thereof and notice to the Commission, may put the proposed rates into effect subject to refund. Ibid.

The scheme is simple. Suspension precedes investigation which precedes determination. This established pattern was not followed by the Commission here.

2. By its "Interim Order" of April 22, 1983, the Commission denied Step 1, the request for an interim increase of \$44 million to take effect on May 1, 1983, and further, without any hearing, denied two components of Step 2: (a) the Company's request for an increased return on equity and (b) the revenue requirements associated with the Company's North Anna Unit 3. The Commission required that these North Anna revenue requirements be removed from this proceeding and considered in a separate proceeding to be established by the Commission. The Order directed the Company to file revised rates excluding these two matters² and it set the application so excised and the rates so filed for hearing before a Hearing Examiner beginning July 19, 1983.

3. On April 27, 1983 the Company filed with the Commission a Petition for Reconsideration requesting the Commission to reconsider its "Interim Order" and to enter an amending order allowing all issues presented by the Company's Application to be considered in a timely fashion at an appropriate hearing and, if the decision had not been made by August 29, to allow rates to go into effect subject to refund in accordance with § 56-238 of the Code of Virginia. In its "Order Disposing of Petition for Reconsideration" on May 13, 1983, the Commission denied the

²In an "Order Suspending Filing Date" of April 29, 1983, the Commission suspended until further order of the Commission the requirement that new rates be filed by April 29. The order of May 13, 1983 again directed the filing of new rates, and they were filed on May 20, 1983.

Company's request, except that it restored to this proceeding one issue that had been previously removed, the treatment of Allowance for Funds Used During Construction related to North Anna Unit 3. That issue, therefore, is not involved in this appeal. The Commission ordered the Company to file revised rates reflecting its decision. The Company did so on May 20, 1983, and these reduced rates will, unless the Court acts, become effective on August 29, 1983.

4. After receiving the "Order Disposing of Petition for Reconsideration," the Company, on May 23, 1983, filed with the Commission its Notice of Appeal and a Motion for Suspension requesting the Commission to suspend, pending decision by this Court, the provisions of the Orders that required removal from this case of the revenues associated with North Anna Unit 3. On June 24, 1983 the Commission entered its "Order Denying Motion for Suspension."

5. The Commission ordered that

" . . . all revenue requirements associated with the cancellation of North Anna Unit 3 and the increase in equity return are denied. . . ." (Order of April 22, 1983, p.6).

It did not suspend and investigate. It simply denied without a hearing. Its action was arbitrary, unreasonable and unauthorized, because it took action in exact contravention of the explicit provisions and intent of the governing statute (see footnote 1 above).

6. The damage to the Company is substantial and irreparable. The Commission's refusal to allow the Company's

requested rate increase related to North Anna Unit 3 to go into effect subject to refund pending the Commission's investigation denies the Company any opportunity to receive revenues attributable to North Anna Unit 3 between August 29, 1983 and the Commission's final order following the investigation. And there is no time limit on how long the Commission will require to investigate this issue. The required removal from this case of the \$65 million annual revenue requirement associated with the North Anna Unit 3 cancellation³ means that each day the Company will suffer a loss of revenues equalling about \$178,000, beginning August 29, 1983.

7. The Commission's denial without a hearing of the Company's request for an increased return on equity likewise causes substantial and irreparable injury. The consideration of the appropriate return on equity is always a major issue in the hearing concerning a rate increase and should have been so here. It is perfectly clear that a decision by the Commission on the remaining rate issues will not be forthcoming by August 29, 1983,

³The Affidavit of B. D. Johnson attached hereto as Exhibit A shows that this consists of the requested increase of \$37 million related to the cancellation of North Anna Unit 3 and \$28 million that is not part of the requested increase in rates. The \$28 million is in the present revenues of the Company; it is the revenue requirement attributable to the investment in North Anna Unit 3 that was included in the 1981 test year used by the Commission in the Company's 1982 rate proceeding to establish the rates now in effect. By ordering that "all revenue requirements associated with . . . North Anna Unit 3" be excluded from the rates it ordered filed, the Commission required the deletion of this \$28 million of existing annual revenues.

the date of expiration of suspension.⁴ If the Commission had acted as it was required to act by law, the Company would begin on August 29, 1983, to collect, subject to refund, \$28 million more in annual revenue associated with the proposed increase in return on equity⁵ than it will be permitted to collect under the Commission's order. This is \$77,000 a day. When combined with the amount reflected by the North Anna Unit 3 decision, the total amount is \$255,000 a day. This is a substantial amount. The action of the Commission removes forever the opportunity that the Company would have to collect these funds, and it thereby denies the Company the right to keep the portion of these funds to which it may ultimately be held to have been entitled. This is clear irreparable harm that cannot be cured by any later action of the Commission or the Court.

8. The action by the Commission that denies to the Company its right under § 56-238 to collect these funds and dismisses the request for an increase in equity return is final action on those issues, and suspension of that action is necessary for the proper administration of justice.⁶ Otherwise the irreparable injury

⁴The Commission has set the matter for hearing before a hearing examiner. He must hear voluminous testimony and prepare and file a report. Time (usually 15 days) must be given to the parties to file exceptions. Only then is the proceeding ripe for Commission decision. All of this cannot be done in 40 days.

⁵See Affidavit of B. D. Johnson attached hereto as Exhibit A.

⁶The Company does not seek suspension of the other provisions of the Orders. Likewise, it does not request that the North Anna 3 issue, which has now been set for hearing beginning

to the Company will continue for an indeterminate period to its permanent harm. If suspension is granted there is no harm to anyone, because the customers who would pay the additional amounts collected by the Company would receive, under §§ 56-238 and 8.01-676F of the Code, refunds, with interest, of any funds collected in excess of the amounts ultimately approved.

9. For the reasons stated above, prompt action by the Court on this Petition and in this Appeal is required to prevent irreparable injury to the Company, and the Company hereby moves the Court to give expedited treatment to these matters.

10. By letter dated June 14, 1983, a copy of which is attached as Exhibit B, counsel for the Company requested the Clerk of the Commission to certify the record on appeal in this case and transmit it to the Court pursuant to Rule 5:18(d) by June 22, 1983. On June 23, 1983, the Clerk's Office advised counsel for the Company by telephone that it was unable to certify and transmit the record because (a) the Commission intended to prepare an opinion, and the record would not be complete until that had been done, and (b) the Commission would not allow certification of an incomplete record. But for this the record will consist of the application of the Company, the Company's pre-filed testimony and exhibits, the Commission's Order of April 22, 1983, the Company's Petition for

December 6, 1983, be heard in the hearing now scheduled in July, but only that the Court suspend the denial of its right to collect, subject to refund, the revenues associated with that issue pending its resolution.

Reconsideration, the Commission's Order of April 29, 1983, the Commission's Order of May 13, 1983, the revised schedules, exhibits and tariffs filed by the Company pursuant to the Orders, the Company's Notice of Appeal and Motion for Suspension, and the Commission's Order of June 24, 1983. A true copy of those documents is filed herewith as Exhibit C.

11. The action of the Commission was arbitrary, unreasonable and not authorized by the governing statutes, and it causes the Company incurable irreparable injury and thereby deprives the Company of property without due process of law. Furthermore, the nature of its action having been forcefully brought to the attention of the Commission, it has refused to correct its manifest error.

The Company, therefore, prays that the Court (a) grant this appeal from those portions of the Orders that denied the Company's request for an increase in return on equity and that denied the Company its right to collect the revenue requirements attributable to North Anna Unit 3 after suspension of 150 days, (b) suspend those portions of the Order until final determination by this Court of their legality, (c) expedite this appeal and (d) allow, pursuant to Rule 5:18(g), oral argument on this Petition.

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

June 28, 1983

By


Counsel

Affidavit

I, B. D. Johnson, being first duly sworn, hereby state as follows:

1. I am Vice President and Controller of Virginia Electric and Power Company (the Company), and in that position I have responsibility for the calculation of the Company's revenue requirements for the purposes of its rate proceedings in Virginia and elsewhere and for the preparation of the accounting testimony and exhibits in those proceedings, and I have performed these responsibilities in the Company's 1983 application to the State Corporation Commission of Virginia (the Commission), Case No. PUE830029.

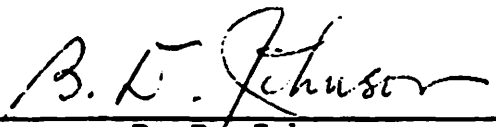
2. I have reviewed the Commission's actions in Case No. PUE830029 as set forth in its "Interim Order" dated April 22, 1983 and its "Order Disposing of Petition for Reconsideration" dated May 13, 1983, by which the Commission denied the Company's request for an increased return on equity and removed from that proceeding all consideration of the revenue requirements attributable to the cancellation of the Company's North Anna Unit

3. Those actions of the Commission removed from Case No. PUE830029 the sum of \$93 million, and the Company has, pursuant to the Commission's orders, filed revised rate schedules and exhibits that reflect the removal of this amount. The \$93 million consists of \$28 million attributable to the requested increase in the return on equity (from 15% to 16%) and \$65

million based on the Company's proposed ratemaking treatment of the cancellation of North Anna Unit 3.

3. Removal of the entire \$65 million related to North Anna Unit 3 involves the elimination of \$28 million of revenues that are presently being collected. The Company's requested rate increase asked for only \$37 million of additional revenues for North Anna Unit 3, because \$28 million of revenues related to that unit are already included in the rates approved by the Commission before the Unit was cancelled. The removal from the case of the full \$65 million, rather than only the \$37 million increment, eliminates the \$28 million that is in present rates. As a result, when revised rates go into effect in Case No. PUE 830029, either pursuant to final order by the Commission or as a result of the expiration of the 150 day maximum suspension period prescribed in § 56-238 of the Code of Virginia, the rates that take effect will reflect a reduction in present rates of \$28 million.

Witness my signature this 27th day of June, 1983.



B. D. Johnson

State of Virginia

City of Richmond

Subscribed and sworn to before me, a notary public in and for the jurisdiction aforesaid this 27th day of June, 1983.

My commission expires 8-3-83.



Notary Public

HUNTON & WILLIAMS

707 EAST MAIN STREET P. O. Box 1535

RICHMOND, VIRGINIA 23212

TELEPHONE 804-788-8200

June 14, 1983

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FILE NO.

DIRECT DIAL NO. 804 788- 8322

BY HAND

Mr. William C. Young, Clerk
State Corporation Commission
Jefferson Building
Document Control Center
Level B-1
Richmond, VA 23219

Application of
Virginia Electric and Power Company,
Case No. PUE830029

Dear Mr. Young:

On May 23, 1983, Virginia Electric and Power Company filed its Notice of Appeal from certain portions of the State Corporation Commission's Interim Order of April 22, 1983 and its Order Disposing of Petition for Reconsideration of May 13, 1983.

Under Rule 5:18(d) of the Rules of the Supreme Court of Virginia the Clerk of the Commission is required, within four months after the entry of the order appealed from, to prepare and certify the record and transmit it to the Clerk of the Supreme Court of Virginia. The Rule also provides, however, the record is to be certified "as soon as possible after the notice of appeal is filed" and is to be transmitted "as soon as it has been certified."

Unless the portions of the Commission's orders from which this appeal is being taken are suspended, Virginia Electric and Power Company will suffer irreparable injury pending the completion of the appeal, and therefore it is important for the appeal to be pursued expeditiously. Accordingly, we will be very grateful if you will, pursuant

HUNTON & WILLIAMS

-2-

to Rule 5:18(d), promptly certify the record and transmit it to the Clerk of the Supreme Court by June 22, 1983.

Thanking you for your cooperation, I am

Sincerely yours,


Evans B. Brasfield

EBB/mn

cc All Parties of Record
bc Mr. T. Justin Moore, Jr.
Mr. W. W. Berry
Mr. O. J. Peterson, III
Mr. B. D. Johnson
Mr. C. M. Jarvis
Mr. P. G. Edwards
Mr. D. R. Hostetler
John W. Riely, Esq.
Richard D. Gary, Esq.
Patricia M. Schwarzschild, Esq.

SUPREME COURT OF VIRGINIA

VIRGINIA ELECTRIC AND POWER COMPANY,

Appellant

v.

STATE CORPORATION COMMISSION and
DIVISION OF CONSUMER COUNSEL OF
THE OFFICE OF THE ATTORNEY GENERAL,Appellees.

Record No. 831040

ASSIGNMENTS OF ERROR

Virginia Electric and Power Company (Vepco or the Company), appellant herein, assigns error as follows to the April 22, 1983 and May 13, 1983 orders of the State Corporation Commission of Virginia (the Commission):

1. The Commission erred by denying, without a hearing, the Company's requests for an increase in the approved return on common equity and for an increase in revenues to cover the revenue requirement related to the cancellation of North Anna Unit 3 in that such action violated Article IX, Section 3 of the Constitution of Virginia and Section 56-237.2 of the Code of Virginia and denied Vepco due process of law in violation of Article I, Section 11 of the Constitution of Virginia and Amendment XIV, Section 1 of the Constitution of the United States.

2. The Commission's summary rejection of the aforesaid requests violated Section 56-238 of the Code of Virginia in that it prohibited the Company from placing in effect, pursuant to

that section, the rate increases related to those requests 150 days after the date the requests were filed with the Commission.

These assignments of error are made without the benefit of an opinion by the Commission. If such an opinion is made a part of the record, Vepco reserves the right, if necessary, to file additional assignments of error.

Dated July 29, 1983

VIRGINIA ELECTRIC AND POWER
COMPANY

By 
Evans B. Brasfield
Counsel

John W. Riely
Evans B. Brasfield
Richard D. Gary
Patricia M. Schwarzschild
Hunton & Williams
P. O. Box 1535
Richmond, Virginia 23212

Of Counsel

CERTIFICATE OF SERVICE

I, Evans B. Brasfield, a member of the Virginia State Bar certify that on July 29, 1983 I have mailed, postage prepaid, or hand delivered a copy of these Assignments of Error to Lewis S. Minter, Esq., P. O. Box 1197, Richmond, Virginia 23209; Donald G. Owens, Esq., P. O. Box 1197, Richmond, Virginia 23209; Kenworth E. Lion, Jr., Esq., P. O. Box 1197, Richmond, Virginia 23209; Gerald L. Baliles, Esq., Attorney General of Virginia, Supreme Court Building, Richmond, Virginia 23219 and Anthony Gambardella, Esq., Assistant Attorney General, Supreme Court Building, Richmond, Virginia 23219.

