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BEFORE THE NEW MEXICO PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE FILING OF PROPOSED CHANGES IN RATES BY EL PASO ELECTRIC COMPANY IN ACCORDANCE WITH STIPULATION AGREEMENT, EL PASO ELECTRIC COMPANY, PETITIONER.	CASE NO. 1833 PHASE II

DIRECT TESTIMONY

OF

PAUL CHERNICK
ON BEHALF OF
THE ATTORNEY GENERAL

December 23, 1985

ANALYSIS AND INFERENCE, INC. RESEARCH AND CONSULTING

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1 - INTRODUCTION AND QUALIFICATIONS

Q: Mr. Chernick, would you state your name, occupation and business address?

A: My name is Paul L. Chernick. I am employed as a research associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Massachusetts.

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. My work has considered, among other things, the need for new power supply investments, and the likely costs of those investments, particularly in nuclear power; the projection of nuclear power plant performance; and the design of power plant performance standards.

In my current position, I have advised a variety of clients on utility matters. My resume is attached to this testimony as Appendix A.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified approximately thirty-five times on utility issues before such agencies as the Massachusetts Energy Facilities Siting Council, the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the Texas Public Utilities Commission, the Illinois Commerce Commission, the Vermont Public Service Board, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Pennsylvania Public Utilities Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, generation system reliability,power plant availability and fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: Have you testified previously before this Commission?

A: Yes. I testified on the economics of the Eastern Interconnection Project in Case 1794.

Q: Do you have a track record of accurate predictions regarding nuclear power plants?

A: Yes. My projections of nuclear power costs have generally been confirmed by subsequent events and current utility projections. For example, in 1979, as part of the Pilgrim 2 construction permit proceeding (NRC 50-471),[1] Boston Edison was projecting a cost of $1.895 billion. I projected a cost between $3.40 and $4.93 billion in my testimony of June, 1979. Boston Edison's final cost estimate (issued when Pilgrim 2 was canceled in September 1981) stood at $4.0 billion.

In MDPU 20055, PSNH projected in-service dates for Seabrook of about 4/83 and 2/85, at a total cost of $2.8 billion. My testimony of January, 1980 predicted in-service dates of 10/85 and 10/87, corresponding to a cost around $7.8 billion. A series of official cost estimate increases ensued, along

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1. Full cites to these cases are given in my resume, Appendix A to this testimony.

with slower increases in improved versions of my own cost estimates.) On March 1, 1984, PSNH released a new cost estimate of $9 billion, with in-service dates of 7/86 and 12/90. Seabrook 2 was effectively cancelled soon thereafter, and the projected completion date for the first unit has now slipped to 10/86. Thus, PSNH's estimates of Seabrook in-service dates and costs increased by a factor of more than three in a little more than four years, and ended up relatively close to my much earlier projections (which were actually somewhat optimistic, and also rose over time).

In MDPU 84-25, Northeast Utilities (NU) projected a total cost for Millstone 3 of $3.54 billion. In my testimony dated April 9, 1984, I estimated that the final cost of the unit would be between $4.5 and $5.5 billion. In the Spring of 1984, NU acknowledged that the cost of the plant would be higher than its previous estimate. While no comprehensive re-estimation has been performed, NU now expects the plant to cost $3.75 to $3.90 billion, with the in-service date still projected at May of 1986.

In Illinois Commerce Commission 82-0026, Commonwealth Edison (CWE) was projecting that the Braidwood plant would be completed for $2.74 billion. In testimony filed in October 1982, I estimated that the plant cost would rise to $4.8 - $5.5 billion, plus inflation due to in-service date slippage. CWE's cost projection for Braidwood now stands at $5.01 billion (some of the increase may be attributable to slippage-related inflation, but the low rate of actual inflation has neutralized much of this effect). Since the second unit is not expected to be finished until late in 1988, there is ample time for further increases.

My projections of nuclear operating characteristics have also been confirmed by experience and by the subsequent projections of utilities and regulators. As indicated in my testimony from the late 1970's, capital additions to nuclear units in operation have continued, the expense of operating the plants has continued to rise, and capacity factors have been much lower than the utilities expected.

Q: Do you have any research experience related to nuclear decommissioning?

A: Yes. I co-authored a research report for the Nuclear Regulatory Commission, entitled Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense (NUREG/CR-2370). That report is attached as Appendix D to this testimony.

Q: Have you testified on insurance matters?

A: Yes. I have been a witness on required profit margins and investment income for Massachusetts Private Passenger Automobile Insurance Rates for 1983, 1984, 1985, and 1986. Several improvements which I developed (often jointly with other Analysis and Inference staff members) have been adopted by the Commissioner of Insurance; in his 1985 Decision, the Commissioner adopted virtually all of our methodological innovations.

Q: Have you written articles and presented testimony on power plant performance standards?

A: Yes. My paper "Power Plant Performance Standards: Some Introductory Principles," published in **Public Utilities Fortnightly**, is attached as Appendix E to this testimony. I have testified on power plant performance standards in four cases: MDPU 1048, MDPU 1509, Michigan PSC U-7775, and Michigan PSC U-7785.

Q: What is the subject of your testimony?

A: El Paso Electric Company (EPE) has proposed ratemaking, financial, and accounting treatment for the decommissioning fund it must establish to finance the eventual retirement, decontamination, and disassembly (or whatever other actions eventually come to comprise decommissioning) for its share of the Palo Verde Nuclear Generating Station (PVNGS). That proposal is presented and explained in the testimony of William J. Johnson filed with the New Mexico Public Service Commission (PSC) on July 15, 1983; in the revised testimony of Mr. Johnson filed May 3, 1985 (referred to herein as "Johnson");[2] and in the responses to interrogatories filed

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2. Additional testimony by Mr. Johnson, filed in November 1985, repeated his earlier presentation.

June 28, 1985 (identified as "IR", with the interrogatory number). This testimony will address certain aspects of the EPE proposal, and provide alternative recommendations. I will also discuss an appropriate interim performance standard for EPE's share of PVNGS Unit 1.

Q: What considerations should the Commission bear in mind in reviewing EPE's decommissioning proposal and alternatives?

A: One of the central issues before utilities and their rate regulators in considering the allowance for decommissioning is the nature of the fund which will be accumulated from an assessments on ratepayers during the useful life of the plant. The fund may be external to the utility, in a bank account or a portfolio of securities. Alternatively, the money may be kept within the utility, as an internal fund. In principle, the internal fund may be segregated or commingled with the other assets of the company. Similarly, a specific mechanism may be established to provide the desired degree of confidence that the fund, as an accounting entity, can be converted into cash when needed, or it may simply be assumed that the value of the fund on the utility's books will actually be available for decommissioning.

In discussing decommissioning, it is important to remember that all aspects of the process are subject to large risks and uncertainties. First, neither the nature nor the average cost of the decommissioning process for large, heavily irradiated nuclear power plants is well known at this time, since no such plants have been decommissioned. The plants which have been decommissioned are very small, most of them have operated for relatively short periods, and most of the decommissionings occurred under much less stringent nuclear safety regulation than would govern worker exposure at a future decommissioning. Second, the average operating life of large nuclear units is similarly unknown: the oldest domestic unit with a capacity of over 1000 MW is still less than 12 years old. Third, the actual useful life achieved by each PVNGS unit, and the cost of its decommissioning, will vary from the average values in presently unknowable ways.

Considering the dismal history of the nuclear industry in projecting the costs of building, running, and upgrading nuclear power plants, it would be prudent to expect sizable increases in the real (inflation-adjusted) cost of decommissioning, perhaps by a factor of several times. Similarly, the limited longevity experience with smaller units, as well as the industry's tendency towards excessive optimism in operating reliability, suggests that the operating lives of nuclear units may be much shorter than the 35 years assumed by EPE. Some of the issues relating to the frequency of premature decommissionings and the cost of both normal and premature decommissionings are included in Appendix D.

Considering the limitations of current utility estimates of unit life and dismantlement costs, it is likely that the decommissioning allowances established on the basis of those estimates will have to be increased as more information becomes available. As a result, the safety and adequacy of decommissioning funds, when they are needed, may be less sensitive to the specific decommissioning assessments allowed in rates over the next few years, which will contribute little to the final balance and which will soon be revised, than to the ratemaking and regulatory concepts adopted, which may persist for many years.[3]

Q: How is your testimony structured?

A: The second section considers the objectives and standards which EPE and the PSC might apply in evaluating alternative approaches. The third section of this testimony describes EPE's proposed accounting treatment and design for the PVNGS decommissioning fund. Section 4 discusses the relative costs (particularly tax treatment) and safety of internal and external funds, while Section 5 considers the tradeoffs between risk and return in the fund investments. Section 6 numerically compares the cost of internal and external funds. Section 7 presents my recommendations and conclusions on funding decommissioning. Section 8 discusses the interim performance standard for PVNGS Unit 1.

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3. For the reasons set forth above, I strongly support Johnson's proposal (page 10) that the decommissioning funding mechanism be reviewed periodically.

2 - OBJECTIVES OF DECOMMISSIONING FUND DESIGN

Q: What objectives may be applied in evaluating decommissioning fund structures?

A: The decommissioning fund is established to accumulate the decommissioning assessments from ratepayers, for the ultimate purpose of paying for the decommissioning of the particular nuclear plant. Several objectives can be applied in evaluating alternative designs for the pattern of assessments over time, the size of the assessments, and the nature of the fund. Johnson (page 8) proposes several such objectives:

- minimize revenues from current customers (whose rates will be increased by PVNGS, even without a decommissioning assessment),
- minimize future revenue requirements, and
- establish a "reasonable fund balance" as early as possible, to provide for the possibility that decommissioning will occur before the end of the projected 35-year life.

I would restate Johnson's third objective more broadly:

- maximize the probability that EPE's share of the cost of decommissioning PVNGS will be available from the fund when it is needed, which would include Johnson's goal of preparing for early decommissioning, and would also subsume such subsidiary goals as:

- minimize the investment risk associated with the fund (a goal Johnson acknowledges at page 5),
- maximize the probability that the accounting value of the fund can be realized (i.e., converted to cash) when it is needed,
- provide for updating the decommissioning charge to reflect changes in estimates of decommissioning cost, unit useful life, interest and inflation rates, and other pertinent factors (see Johnson, page 10),
- minimize the probability that future ratepayers will have to pay for decommissioning a plant which did not serve them, and
- minimize the probability that future shareholders will have to pay for decommissioning.

Some of these goals are mutually consistent: for example, minimizing the fund's investment risk reduces the probability that future ratepayers or shareholders will be left with the cost of decommissioning, and reducing those probabilities also reduces the risk that no one will be willing or able to put up the funds. Some goals are mutually inconsistent: minimizing the cost to current ratepayers will tend to increase the risk to future ones, for example.

The one objective listed above which may be most controversial is the maximization of the probability that EPE can pay for PVNGS decommissioning. It may be argued that the interests of New Mexico EPE ratepayers will be best served by providing financial support for decommissioning only to the extent required to maintain the plant's operating license, since PVNGS is in another state, and it will thus be Arizona's problem in the event of an early or expensive decommissioning. This is a short-sighted view: I will assume for the purposes of this testimony that neither EPE nor the PSC would take that view.

3 - EPE's PROPOSAL

Q: What types of decommissioning funds does EPE present in its testimony?

A: Johnson discusses three alternative decommissioning fund structures:

1. An external fund, to be invested in Treasury securities, with after-tax interest accruing in the fund (Exhibit WJJ-1). The contributions to the fund would be tax deductible, but both interest on the fund and withdrawals from the fund would be taxable.

2. An internal fund, which Johnson denominates the "three year increasing straight-line" or "modified straight line" method (Exhibit WJJ-3).[4] Contributions to the fund would be taxable, but withdrawals would not be. Interest would be returned to the ratepayers, as a reduction to rate base, rather than accumulated in the fund.

3. An alternative internal fund, which Johnson denominates the "internal sinking fund" method (Exhibit WJJ-2). Contributions to the fund would be taxable, but withdrawals would not be. Most of the interest would

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4. In fact, the rate of fund accumulation is nowhere near a straight line, and is more like a parabola.

accumulate in the fund, but a small portion would be returned to ratepayers as an offset to rate base.

All three of Johnson's Exhibits presenting his methods are included in my Appendix C, along with his Exhibit WJJ-4, which compares some characteristics of the three methods.[5] Unfortunately, Johnson's Exhibits are far from self-explanatory: they occasionally use the same term for two distinct concepts. Johnson's text provides no explanation of the Exhibits, so I will provide some here.

The term "Annuity" in Appendix C refers to the annual explicit charge added to rates to fund decommissioning. For Exhibit WJJ-1, the Annuity <u>is</u> the revenue effect, and the only other quantity of interest is the Fund Balance, which is the sum of last year's balance, this year's annuity, and the after-tax interest (which Johnson estimates at 4.86%) on last year's fund balance. Starting in 2018, decommissioning expenses are subtracted from the Fund Balance, in the year they occur.

For Exhibit WJJ-3, the calculation of the Fund Balance is simpler, but the computation of the revenue requirement is much more complex. No interest accrues in the fund, so the

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5. Since Johnson strongly prefers the "modified straight line" approach, and since I do not consider either of the two internal fund approaches to be appropriate, I will not discuss the "internal sinking fund" further. Henceforth, I will use the term "internal fund" to signify Johnson's modified straight line method, although many of my comments are applicable to any internal fund.

Fund Balance is the previous year's balance, plus the new Annuity. Revenue Required, the value of immediate concern to ratepayers, is the difference between the Annuity added to rates, and the reduction in rates due to the decrease in the rate base by the size of the Fund Balance. Johnson assumes a 10.17% return to the ratepayers from the rate base offset.[6] Interestingly, the Fund Balance column in Exhibit WJJ-3 (and in WJJ-2, as well) is inconsistent with Johnson's Exhibit WJJ-4 (column 7 for the modified straight line, column 9 for the sinking fund), which shows much smaller Fund Balances for the internal funds.

Q: Why are Johnson's Exhibits internally inconsistent?

A: Johnson has basically stated the internal fund balance as if it were twice its realistic size, given the ratemaking he suggests. In fact, he misstates three points. First, since contributions to the internal fund are not tax deductible, about $2 are required from rate payers to place $1 in the fund. The other dollar goes to the IRS.[7] Second, once the $1 is in the fund, EPE assumes that it displaces $1 of EPE's normal financial structure, offsetting $1 of rate base and returning $0.1019 annually to the ratepayers. Table 1

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6. EPE does not explain the origin of its assumed 10.19% return further. See IR-3. As we shall see in a minute, this is much smaller than the return the ratepayers should earn on the rate base reduction.

7. Thus, at the end of 1986, we expect a $650,000 annuity (charge to ratepayers) to produce the $330,000 Fund Balance shown in Exhibit WJJ-4, not the $650,000 shown in Exhibit WJJ-3.

demonstrates that the actual revenue effect of the fund's offset to ratebase is more like 20% annually than the 10% assumed in Johnson's Exh. WJJ-3. Third, if all goes as Johnson plans, each $1 withdrawn from the decommissioning fund will actually pay for almost $2 of net decommissioning expenses, since the expense is deductible (generating about $1 of tax reductions per $2 expense), but the withdrawals from the fund are not taxable. Thus, only about half of the decommissioning expenses should be subtracted from the balance.

Q: Is EPE's presentation incorrect?

A: Even though the individual elements in Exhibit WJJ-3 are mostly wrong, that Exhibit is essentially correct in its overall conclusions about revenue requirements, because the misstatements cancel one another:

- The fund balance (column 5) is about twice as large as it would really be, since it is stated as if all collections from ratepayers went into the fund, when half go to the IRS.

- The return to ratepayers is 10.19% annually, about half of its realistic level. Multiplying twice the realistic balance (from column 5) by half the realistic return produces the proper offset to rates (subtracted from column 2 to produce column 6).

- Decommissioning expenses are stated without recognizing their tax deductibility, which would halve their effective size, if the utility has a positive tax burden for them to reduce. Thus, column (4) is doubled, as is column (5), from which it is subtracted.

Exhibit WJJ-3 is unnecessarily confusing, and obscures the fact that half of the assumed value of the internal decommissioning depends on EPE's having a positive tax liability, as I will discuss below.

4 - INTERNAL VS. EXTERNAL FUNDS

4.1 - Security

Q: What is EPE's position regarding the relative safety of internal and external decommissioning funds?

A: EPE has repeatedly asserted that an unrestricted internal fund can be just as secure as an external fund (Johnson page 6, lines 1-5, and page 7, line 21, to page 8, line 2; IR-1). An internal fund could be said to be as secure as an external fund if the investment risk associated with the funds were equivalent; that is, if the internal fund were just as likely as the external one to actually be able to produce the cash required for the decommissioning (or at least the amount of money expected to be available for the purposes of the decommissioning financing plan).

Q: Is EPE correct?

A: No. It seems intuitively obvious that funds tied up in the operation of a company are intrinsically <u>insecure</u>. The value of corporate assets and operations are subject to random variation, and there is no assurance that an investment (or the anticipated income on the investment) in the corporation will be available at any time in the future. After all, the accounting entity (the fund) must be converted into cash, and this can only be done by issuing securities against the firm's assets or business prospects, or by selling some of the assets. The liquidity of the internal fund is particularly uncertain when it is to be withdrawn following an adverse event for the company, such as an early or expensive decommissioning. Equity may sell well below book, new debt may require extraordinary returns, and some security issues may not be allowed (by charter or indenture) or be unsalable.[8] Internal funds place all the decommissioning reserve eggs in one basket, which is none too secure in any case, and which is most likely to tip over when the eggs are really needed.

Q: Does the fact that EPE is an electric utility exempt it from the inherent insecurity of internal funds?

A: No. Utilities are somewhat more secure investments than the typical corporation, but the last decade has illustrated several ways in which utilities can get into serious financial trouble. Perhaps the most obvious example is the experience of General Public Utilities following the accident at Three Mile Island, which simultaneously created a serious cash requirement and removed a major asset from service (and

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8. Even the securities which can be sold do not fully protect future ratepayers, if they wind up paying higher rates to cover the inflated interest on the debt and to generate earnings for an inflated quantity of stock. If the higher costs are not absorbed by ratepayers, of course, they will be borne by shareholders, at least to the extent the shareholders can absorb those costs.

hence from rate base). This is exactly the kind of problem to which internal decommissioning funds are most vulnerable.

Other recent examples of severe utility financial distress resulted from a second source: the cost of generation projects under construction, cancelled, or in service. The owners of cancelled nuclear plants and plants still under construction lead this list, including among others

- Consumers Power (Midland cancellation),
- Public Service of Indiana (Marble Hill cancellation),
- Long Island Lighting Company (Shoreham construction), and
- Public Service of New Hampshire, United Illuminating, Maine Public Service, Fitchburg Gas & Electric, and other New England utilities (Seabrook 1 construction, Seabrook 2 cancellation).

Even when plants are in service or are non-nuclear there have been similar financial problems generally due to disallowance of imprudent costs. LILCo may be in very serious financial condition because of the NYPSC's imprudence findings ($1.35 billion was disallowed out of the total cost of about $4.5 billion), even if Shoreham reaches commercial operation. Mid-South Utilities financial condition deteriorated rapidly following commercial operation of Grand Gulf 1, as AFUDC accrual stopped and rate increases were rejected. Montana

Power had considerable financial difficulties following commercial operation of a coal unit, the cost of which was entirely disallowed by the Montana PSC on prudence grounds.

The third type of financial stress has been caused by the accumulation of normal operating problems: rising costs, falling sales, limited ability to raise rates, and increased construction burdens. Most electric utilities have suffered from these problems, to some degree, over the last 15 years, but the prime example is Consolidated Edison in the mid-1970's. While other utilities' problems were less severe, they at least would have raised the cost (to ratepayers and/or shareholders) of converting an internal decommissioning fund into cash.

Q: Has EPE attempted to demonstrate the security of an internal fund?

A: No. Despite the obvious utility counter-examples which I cited above, EPE has insisted that "an internal unrestricted fund is as secure as an external fund" (Johnson, page 6, and IR 1). This is simply not true. As happened to GPU, problems with PVNGS can both require premature (and particularly expensive) decommissioning, and render the utility unable to pay for decommissioning. As has happened to several utilities recently, a construction or operation problem at another plant may greatly limit the utility's ability to finance decommissioning, anything else for that matter: imagine how hard it would be for Consumers Power to decommissioning Palisades, in its present financial position.[9] The general problems of the last 15 years may also recur, perhaps even more intensely, depending on the trends in EPE's costs, the economy in its service territory, and the cost and availability of customer generation, fuel switching, and conservation options.

Q: What is the origin of the insecurity of the internal fund?

A: The problem is largely caused by lack of diversity. An investor who bought only EPE stock and EPE bonds (as EPE suggests the fund should do, in effect) would be taking a large risk due to the lack of portfolio diversity without gaining any benefits, compared to a portfolio of securities from a mix of utilities (electric, gas, telephone), geographically dispersed, with varying fuel sources and customer types. Each of the utilities could pose the same range of risks as does EPE, but since bad results at one utility will tend to be balanced off by good results of another utility, the returns and value of the mixed portfolio will be more stable than those of EPE (or any other similar utility) by itself.[10] Portfolio variation can be further

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9. Depending on the circumstances surrounding the decommissioning, the shareholders may be required to pay for a portion of the decommissioning cost, further weakening the utility's financial position just as it is trying to convert the fund's assets into cash.

10. Even a portfolio containing only the securities of a single other utility, not involved in PVNGS would provide some diversity, since at least the need to call on the fund would

reduced with no reduction in return by broadening the portfolio beyond utilities. Not all risk can be eliminated in this way, since the capital markets tend to move together, but the diversified external portfolio can certainly be safer than the internal portfolio.

Q: How important is diversity in reducing investment risk?

A: Table 8 presents an example of the benefits of diversity, adapted from **Investments**, by William F. Sharpe (page 160, Second Edition, 1981). Diversifying the portfolio sharply reduces the variability in the annual return, and narrows the range of long-run returns which can be expected with any given probability. For this example, increasing the portfolio from one stock to 30 stocks increases the minimum average return in a 95% confidence interval over 10 years from -7.6% to 2.0%, and over 20 years from -1.0% to 5.9%. Remember that one company in fifty would have worse results than those shown in Table 8. The relationships of these measures of low-end (but not minimum) return to portfolio diversity are displayed in Figure 3. These are arithmetic average returns: the compound average return (which is the figure of real interest) will be more volatile. In addition, the simple model I use assumes that returns are normally distributed and therefore does not reflect the possibility of

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not be correlated with other problems for the utility whose assets support the fund.

bankruptcy or severe financial distress, which would further increase the variability in return for the small portfolios.

Q: Does EPE offer any argument for its position on the security of an internal fund?

A: EPE basically wishes away the risk and diversity problems of internal funds. Asked for the basis of the assertion that "an internal unrestricted fund is as secure as an external fund," EPE replied that there have been "a number of bankruptcies and defaults in public bonds," that is, in municipal bonds,[11] but that "[c]urrently there has not been a publicly-owned [i.e., investor-owned] utility within the United States which has declared bankruptcy" (IR-1). This statement is a non-sequitur for several reasons. First, EPE actually compares its proposed internal fund to an external fund investing solely in Treasury securities, which have no default risk, not to municipal bonds, which range from the fully insured to the highly speculative. Second, if investor-owned utilities (IOUs) are particularly safe investments, the external fund could consist entirely of securities issued by IOUs. Third, it is clear, from the examples I gave above, that financial distress well short of bankruptcy can interfere with realizing the book value of a decommissioning fund, or perhaps any value at all.

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11. Municipal bankruptcies are very rare, and defaults for any length of time are also quite unusual, although WPPSS certainly demonstrated that they can occur.

EPE was also asked about its ability to liquidate the proposed internal fund, and generate cash for decommissioning, in the event that it were in a condition similar to those of the various utilities listed above (IR-2). The response indicated that only GPU's situation had anything directly to do with decommissioning. That is true, and it is certainly fortunate that a premature decommissioning has not been added to the burdens of the other utilities, but it would hardly be prudent to assume that EPE will be similarly fortunate. The response also points out that the GPU is not bankrupt, but does not deal with the issue of GPU's inability to finance the decommissioning of Three Mile Island Unit 2.

Q: What requirements should be placed on an internal fund?

A: Since EPE has no valid response to the obvious criticisms of internal funds, it would be extremely naive to assume that whatever funds the PSC had allowed EPE to collect for decommissioning will actually be available when they are needed. This is particularly true for a utility (such as GPU, MSU or EPE) serving more than one state: regulatory actions and other events in the second state may influence the ability of the utility's shareholders to provide the cas on demand. At the very least, before EPE relies on an internal decommissioning fund, it should

- demonstrate that it can establish an internal fund which will have an effective claim on "an asset which can be used as collateral to secure the funds needed" (page 6), even under very adverse circumstances;

- demonstrate that the decommissioning fund will have a senior claim on the collateral asset, even prior to that of the senior bondholders; and

- identify assets which can be associated with the fund, and which will be likely to have market value as collateral in the long term, and show that the such assets can be sold or pledged to secure the cash value of the decommissioning fund, without increasing rates to customers,[12] or

- demonstrate that EPE assets which are only valuable because of the utility's right to charge ratepayers for their use (e.g., transmission and distribution equipment) will be useful for securing cash, even at times of severe financial stress to EPE.

If, for example, EPE intends that its coal reserves will be the asset securing the decommissioning fund, it should demonstrate that it could issue securities using the assets as collateral or sell those assets (if necessary) without

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12. For example, if EPE sold a very cheap coal plant to raise the cash for decommissioning PVNGS, customer rates would be expected to rise, defeating the whole purpose of having a decommissioning fund, which is to avoid having the customers pay for the bulk of decommissioning at the time it occurs.

increasing customer rates,[13] and without violating the rights of its security-holders. This demonstration involves both factual issues (the existence of other markets for EPE coal, the ratemaking effect of the sale) and legal issues (the terms of EPE bond indentures).

If EPE has other problems at the time of PVNGS decommissioning (such as those of the utilities I discussed above), assets which are only valuable in EPE operations may offer little security for the fund. If the problems affect other utilities in the region, even assets which can be sold may have little value: falling regional electric sales may sharply reduce the value of EPE coal reserves, for example. Thus, I see no way in which an internal fund can ever be as secure as an external fund.

Q: Has EPE demonstrated that it could convert its proposed internal fund to cash, in the event of an early or expensive decommissioning?

A: No. EPE declined to provide any concrete demonstration of the feasibility of liquidating its decommissioning fund, and simply asserted that the assets "could be used as collateral for financing" (IR-2), which may or may not be true, but even

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13. Of course, if the decommissioning fund has been decreasing rates, that effect would stop, and rates will rise due to the absence of the fund. The point here is that rates should not rise due to sale of the asset (or associated securities) below book value, or due to the sale of securities with yields higher than normal market rates.

if it is true, hardly guarantees that the ratepayers will get back the value they put into the fund.

4.2 - Tax Treatment of Internal and External Funds

Q: What tax issues are related to the cost of alternative decommissioning funds?

A: There are two basic problems in EPE's analysis of the tax treatment of the funds it compares. The first problem concerns the taxation of the external fund investment income, and the second concerns the effective size of the internal decommissioning fund.

Q: Please describe the investment income tax error in EPE's proposal.

A: The first problem arises from EPE's assumption that the external fund will be composed of Treasury bonds, which are taxed at 46% like all other taxable interest income. The 9% gross yield on the Treasury bonds (rather a low figure, at this time, for the medium-term and long-term securities of interest here) becomes 4.86% after taxes. In fact, if the portfolio were composed of electric utility stocks and bonds essentially identical to those of EPE,[14] the effective tax rate would be much lower, since most of the return is

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14. The portfolio could represent securities of many utilities, or just one of characteristics similar to EPE. They could even be EPE securities, if the IRS permitted that, although it would be more efficient to diversify the portfolio.

dividends and capital gains on the equity, which has much lower tax rates.

Table 2 computes the pre-tax and post-tax returns, and the resulting tax rate, for an external fund more comparable to EPE's internal fund. The indicated tax rate of 28% is overstated, since it assumes that taxes on capital gains are paid annually, when they are actually paid only when the asset is sold. Since most of the assets would be sold when decommissioning took place, the taxes would be deferred significantly, allowing for accumulation of more funds in the meantime.[15] The tax liability can be further decreased by replacing some mix of the common equity and debt with preferred stock, which pays only dividends and is thus taxed at 6.9%.

Q: Please explain the problems in EPE's treatment of the effective size of the decommissioning fund.

A: This second problem concerns the comparison of the fund balance to EPE's estimate of the cost of decommissioning, as presented in Johnson's Exhibit WJJ-4. Columns (7), (8), and (9) of that Exhibit present the projected levels of the three types of decommissioning reserve funds Johnson considers, while Column (10) is about half of EPE's estimated cost of a normal decommissioning, inflated at 6% to the particular

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15. As a side benefit, if EPE were in financial distress at the time of decommissioning, and had no current tax liability, the capital gains might never be taxed.

year. Johnson did not explain his reason for understating the decommissioning cost, but it appears that Column (10) is an after-tax cost. For every $2 of decommissioning costs, income tax liability decreases about $1, leaving a net cost of $1 to be paid by the utility. This approach is appropriate if

- the utility has a positive tax liability, so that the decommissioning tax deduction is useful, and

- the withdrawals from the fund are not taxable.

Unfortunately, neither condition is met consistently. The second condition fails for the tax deductible external fund; taxation of withdrawals from the fund will match the tax deductions from the decommissioning expense, requiring $1 in the fund per dollar of decommissioning expense. The first condition may fail for the internal funds at the worst possible time: if EPE is in financial distress when decommissioning is required, it is unlikely to be paying any taxes, and the deductibility of the decommissioning expenses will not be useful. Thus, the external fund should always be compared to the full cost of decommissioning, and the internal funds should be compared both to the full cost (for planning normal decommissioning) and to the tax-affected cost (for assessing the adequacy of the fund for decommissioning which is early, expensive, or just at a bad time for EPE.)

5 - RISK AND RETURN

Q: How has EPE made incorrect assertions regarding risk and return, for alternative fund structures?

A: In addition to the lack of diversity in the "portfolio" of the internal fund, EPE assumes that the internal fund will earn a higher pre-tax return than the external fund. This follows from the assumption that the external fund will be invested in Treasury securities, which have low yields, while the internal fund will be invested in EPE's capital structure, which has a higher expected return.

Of course, EPE has to pay more for capital than does the Federal government for a reason: investing in EPE, even as part of a well-diversified portfolio, is inherently risky. EPE's stock and bond prices fluctuate with the capital markets and due to changes in EPE's financial condition and riskiness, EPE's equity dividends are not guaranteed, and even the interest and principle on debt might not be paid in the event of bankruptcy. The value of Treasury bonds varies during their life, due to fluctuations in market interest rates, but the credit rating of the Government does not change, and the payment of the interest and principle are never in question. Thus, the difference in pre-tax return (about 13.5% for the internal fund, and 9% for the external fund in EPE's example, which should now be more like 11-12%)

must basically represent a difference in the riskiness of the investment.

Q: How does EPE explain the differences in return on the two funds?

A: EPE attributes the return differential to "current market conditions" and asserts that "it does not give any indication of a risk differential" (IR-3). EPE also claims that "the return earned by the utility is generally higher than an alternative return which could be earned in the open market" (ibid.). If the latter claim were correct, the PSC should reduce EPE's rate of return to a level competitive with the "open market". However, the comparison EPE is making is not to a comparable alternative, but to much safer investments. EPE would not be pleased with a rate of return equal to T-bill rates, and a PSC order setting EPE return at that level would be unlikely to withstand judicial scrutiny, at least in the long term.

Q: What are the implications of EPE's treatment of return on the alternative funds?

A: EPE's treatment of the external fund is fundamentally inconsistent with its treatment of the internal fund. An external fund can either be structured to be essentially risk-free (by investing in Treasury securities), or to be a risky, but well-diversified, portfolio (a wide range of securities and assets of various forms and from various industries). A diversified risky portfolio will vary in value with the general economy, but no misfortune of a single company, industry, or region will materially affect its value. Depending on the division of the portfolio between common stock, preferred stock, taxable bonds, tax-exempt bonds, and other investments, and on the financial condition and credit-worthiness of the security issuers, the external portfolio may be very safe (with a low expected return) or very risky (with a high expected return).

The choices are much more limited with the internal fund. It may be as safe as EPE's best assets (if those can be separated) or as risky as its equity. The internal fund can not be made risk-free.

Any comparison between internal and external funds should be consistent in terms of the risk, and the pre-tax return, of the portfolio.

6 - A FAIR COMPARISON

Q: Please summarize the problems with EPE's comparison of the internal and external fund structures.

A: As explained in the previous sections, the EPE comparison of internal and external funds is biased in favor of the internal funds, by the use of an external portfolio which is of much higher investment quality than the internal portfolio, and which therefore produces lower yields. Even given the nature of the portfolio, the interest rate assumed is too low. The external portfolio is also chosen so as to be taxed at the maximum possible rate, introducing additional bias towards the internal funds.

The comparison of the decommissioning fund balance to the EPE-estimated cost of a normal decommissioning in any year is not consistently biased, since the cost is understated with reference to both internal and external funds. Overall, EPE's errors in the balance comparison are somewhat favorable to the external fund.

Q: How have you corrected EPE's errors?

A: To correct these problems, I have compared the cost of EPE's preferred internal "modified straight line" fund to an external fund with an identical pre-tax return, and more realistic tax treatment. Both the external portfolio and the internal portfolio are assumed to be composed of equal parts

of utility bonds yielding 12%, and utility common stock earning 15%. For the external fund (which is the only place it matters), it is assumed that the common equity earnings are received 80% in dividends, and 20% in capital gains. From Table 2, we know that this portfolio will earn 13.5% before taxes, and 9.91% after taxes in the external portfolio.[16] Assuming a tax multiplier of 1.97 on equity, the return on the internal fund would be
(15 * 1.97 + 12) / 2 = 20.78%.[17]

Despite the similarities in the portfolios, the external portfolio is diversified and is therefore still much safer than the undiversified internal portfolio.

Q: What are the results of your corrected analysis of the external fund?

A: Table 3 presents the equivalent of Johnson's Exhibit WJJ-1, the calculation of the revenue requirement for the external fund, except that the annuity is selected for a 9.91% after-tax return, rather than the 4.86% return EPE assumed. The required annuity (which I also label as the net revenue requirement, for clarity) is $493,000 annually, rather than Johnson's $1,573,000.

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16. As noted previously, the effective taxes would actually be somewhat lower, due to the deferral of capital gains taxes.

17. The corresponding pre-tax return on the internal fund (the form EPE appears to use in computing its 10.17% return) would be 10.55%, so the overall return figures in my examples are close to those EPE used in its internal fund examples (Johnson Exhibits WJJ-2 and WJJ-3.)

Q: What are the results of your simulation of Johnson's proposed internal fund?

A: Table 4 presents the equivalent of Johnson's Exhibit WJJ-3, the calculation of the revenue requirement for the internal fund, except for the use of a slightly different return (for consistency with Table 3); and the clear, correct labeling and presentation of charges to ratepayers, contributions to the fund (after taxes are subtracted from the charges to the ratepayers), and the size of the fund. The decommissioning expenses are assumed to be tax-affected -- EPE is assumed to be paying taxes in 2018 through 2023. The detailed revenue requirements by year differ slightly from those of EPE, but the general pattern is the same: net increases in revenues of $500,000-600,000 in the first three years, followed by variable increases averaging about $1,000,000 annually through 2001, followed by a rapid decline and large credits in the last couple decades of the fund's assumed life.

Q: Have you checked your analyses, to ensure that they have properly captured the ratemaking effects of the various decommissioning fund structures?

A: Yes. I have constructed a simplified ratemaking model, which is presented as Appendix B. Table B-1 computes the revenue requirements for a hypothetical utility with no decommissioning expense. Table B-2 computes the revenue requirements for the same utility, with an external fund added, at an annual fund contribution of $493,000. Table B-3 performs the same calculation, for a utility with Johnson's preferred internal fund charges, and corresponding changes in taxes and in return. Table B-4 summarizes the three cases, and computes the net revenue effect of each of the funds. The differences in revenue requirements in Table B-4, and the fund balances in Tables B-2 and B-3, are identical to the corresponding quantities in Tables 3 and 4.

Q: How do the alternative funds compare in terms of revenue requirements and the accumulation of the fund balance?

A: The annual charges to ratepayers are greater for the internal fund than for the external fund for every year through the end of the century. At a 16% discount rate (which is a reasonable approximation of an overall ratepayer discount rate), the present value of the revenue requirements is about 40% larger for the internal fund than for the external fund. The external fund also accumulates somewhat faster, especially in the early part of the next century, but the differential tax effects on fund withdrawals result in the internal fund being more valuable, <u>if</u> EPE is actually paying taxes when an early decommissioning occurs.

Q: In your examples, the fund balance accumulates more rapidly in the internal fund than in the external fund. Is this difference due to the different accounting procedures?

A: The patterns of net revenue requirements and of fund accumulation over time vary considerably between Table 3 and

Table 4, but this is not intrinsic to the accounting procedure. Table 5 shows the results for an external fund which has net revenue requirements similar to those of EPE's preferred internal fund, for the first 16 years. The annual revenue credits in the next century are levelized in this example, but they too can be shaped in any desired fashion. The present value of the revenue requirement is virtually the same as that from EPE's internal fund. The fund balance accumulates even faster in Table 5 than in Table 3, and is 75% greater than that of the levelized external fund by the turn of the century.

Table 6 compares the annual revenue requirement streams for the funds assumed in Tables 3, 4, and 5, while Table 7 compares the decommissioning fund balances. Figures 1 and 2 present the same information graphically.

7 - CONCLUSIONS ON FUNDING DECOMMISSIONING

Q: Please summarize your conclusions regarding the comparison of internal and external decommissioning funds.

A: External funds can produce fund balances greater than or equal to those of internal funds, with annual revenue requirements less than or equal to those of the internal fund, and with greater assurance that the book value of the fund will actually be available to pay for early or expensive decommissioning.

The advantages of the external funds are particularly great if the decommissioning occurs in conjunction with (or causes) financial distress for EPE: if an early decommissioning occurs without materially affecting the financial condition of the utility, the absence of taxes on withdrawals from the internal fund increases the effective size of the fund. Since the internal fund is least valuable when it is most necessary, it does little to solve the most severe problems a premature or expensive decommissioning can produce.

Overall, the external fund approach appears to be highly preferable to the internal funds.

Q: Do you have any recommendation regarding the ultimate size of the fund, or the date at which it should be designed to reach that size, and be prepared for decommissioning?

A: If the Commission had to decide those issues today, I would recommend that the fund be structured so as to accumulate at least six times EPE's projected decommissioning cost by the time the plant is 25 years old, or about $450 million in 2010, as opposed to EPE's target of $130 million in 2020. Scaling up the revenue requirements from my Accelerated External Fund approach, my best estimates of decommissioning cost and timing would require an annual assessment of about $8 million from 1989 to 2001.

Fortunately, it is not necessary for the PSC to determine in this proceeding what rates will be charged in 2001, or even in 1989. Once the relevant ratemaking techniques and the nature of the fund have been selected, the annual contributions can be fine-tuned to reflect changing information and expectations. As better estimates are developed for the cost of decommissioning, the expected operating life of PVNGS, the risk of early or expensive decommissioning, and projections of future ratepayer costs, the annual assessments may be increased or decreased. In any case, the first few years will accumulate relatively little cash in the fund. Considering the rate shock effects of PVNGS, it is not reasonable to firmly bind ratemaking in this initial period to the long-run cost of decommissioning.

Q: Have you prepared any examples of how the decommissioning assessment might be adjusted over time?

A: Yes. Tables 9, 10, and 11 provide three examples of the adjustment process. All three cases assume that the decommissioning charge is set at $600,000 in 1986, and reviewed triennially. Adjustment Case 1 (Table 9) assumes that EPE's projections are confirmed (or at least not refuted) as new evidence becomes available, and that significant rate shock is experienced as PVNGS ~~are~~ is (hypothetically) phased into rates in the late 1980's and early 1990's. The PSC may thus decide to keep the decommissioning charge at its low initial rate until the phase-in is completed (which I have assumed to be in 1994), and then accelerate fund accumulation so that the balance coincides with that in Table 8 by 2001. The lower rates in 1989-1994 require higher charges ($1,600,000 annually) for the rest of the century, as one would expect. Overall, this pattern of decommissioning cost recovery might better fit the time pattern of PVNGS's other costs and benefits.[18]

The second Adjustment Case (Table 10) supposes that the fund is collected as in Table 5 until 1995, at which time the expected useful life of PVNGS is revised from 35 years down to 25 years. The problem then becomes one of accumulating $76,145,000 by 2010, assuming that EPE's decommissioning cost estimate is correct in real dollars, and that the probability

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18. In general, I would prefer to first guarantee the collection of the decommissioning fund in a timely manner, and than adjust the time pattern of other cost recovery to ameliorate rate shock, but this Case indicates that the process can be reversed, if necessary or desired by the PSC.

of still earlier decommissioning then appears small. The annual charge for 1996-2010 is then a bit over $700,000.

Table 11 presents the third (and most pessimistic) Adjustment Case, in which EPE's estimate of PVNGS longevity is confirmed, but the estimate of decommissioning cost increases over time. I have supposed for this Case that the annual assessment is increased by $600,000 at every triennial review.[19] This process would produce a fund of nearly $600 million in 2020, about four times as much as EPE expects to need.

Table 12 summarizes the Adjustment Case balances and compares them to the balance from the Base Case, the accelerated external fund of Table 5. Figure 4 graphs the annual revenue requirements from each Case, and Figure 5 graphs the fund balances.

Q: Do you project that the evolution of the decommissioning fund will follow the path of any one of these Cases?

A: No. These are only examples of ways in which the decommissioning charge may be adapted to changing circumstances over time. Given the great flexibility in the

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19. Despite these increases, the ratepayers in the last years of the unit's life will be paying less than twice as much in real terms as those in the first year. In the meantime, assuming standard ratemaking, the later ratepayers will be paying less for power which has become more valuable as the costs of alternatives rise.

PSC's possible responses, I see no reason for any party to attempt firm predictions of a set of highly uncertain values.

Q: Do you have any recommendations as to the nature of the fund investments?

A: Yes. From the viewpoint of the ratepayers, it is desirable to minimize investment risk, since the lower decommissioning charges due to the higher return on riskier investments would reduce rates for all ratepayers, but the risk of an investment shortfall would be borne by later ratepayers. On the other hand, favorable tax treatment is only possible by the use of somewhat risky investments, such as preferred stock (taxed at 6.9%), common stock (taxed at about 11.1% for high-payout stock, such as utilities, and at up to 28% for low-payout stocks), and municipal bonds (which are not taxed, but whose lower yields are equivalent to an implicit tax rate of about 27%, as shown in Table 13).

I believe that the best way out of this dilemma is to require the stockholders to take the additional risk necessary to achieve the lower tax rate, and to compensate them for the risk they take by allowing them to retain the higher return. This is the approach taken in determining investment income offsets to regulated insurance rates, as in the methodologies I have helped develop and which have been accepted by the Massachusetts Commissioner of Insurance. Thus, I would suggest computing the return on the fund as if it were comprised of Treasury securities (initially, one third each ten-year, twenty-year, and thirty-year maturities, to cover the range of likely decommissioning dates), with a tax rate based on a tax-efficient portfolio. When the fund is liquidated, the shareholders would be entitled to keep any surplus in the fund, above the imputed value based on ratepayer contributions and the imputed interest rate. At the other extreme, if the fund is less than the imputed ratepayer investment, the shareholders would be expected to make up the difference. Figure 6 displays the probability distribution for a simple fund accumulation example: ratepayers contribute $500,000 annually for 30 years, which is actually invested at a 14% expected pre-tax return,[20] of which 11% is credited to the ratepayers. Both the actual and imputed effective tax rates are 17%. Due to the difficulty of analytically modeling uncertainty in compound growth, this example is evaluated with a Monte Carlo simulation of 535 cases. At the end of 30 years, the ratepayers receive credit for a fund balance of $76 million, while the expected size of the fund is about $106 million, giving the shareholders an expected profit of $30 million, for <u>no additional investment</u>. The probability of the balance being less than the imputed $76 million is about 5%; there is also a corresponding 5% probability that the shareholder profit from the fund will exceed $80 million. The worst case I found in this

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20. This return would correspond to a investment about one-third as risky as the stock market, which would be expected to have a standard deviation of 7.3% in its annual return.

simulation was a balance of $55 million, exposing the shareholders to a $21 million loss; the best case balance was $215 million, for a gain of $139 million.

Since EPE has indicated that it will accept an investment as risky as its own capital structure, the model efficient portfolio might consist of equal parts high-payout common stock (taxed at 11% to 25%, depending on payout), municipal bonds (implicitly taxed at 27%), and preferred stock (between common stock and bonds in risk level, and taxed at 6.9%), for an overall tax rate of 15% to 20%. A 17% tax rate should be readily achievable: at present Treasury rates of about 10%, the imputed after-tax return would be around 8%. EPE's shareholders would expect to earn a much higher actual return from the fund portfolio, which would compensate them for the risk taken. The added return should increase the value of EPE's stock by about the same amount as the increased risk would lower it.

To assure that the company is able to make good on the presumed value of the fund, I would suggest that the PSC require an annual report from EPE detailing the market value of the fund assets, and demonstrating the cash-generating potential of other EPE assets which could be used to fulfill the fund's obligations, should the fund's market value fall. I would suggest that the total demonstrated assets should be at least 1.25 times the accounting value of the fund.[21] I would also recommend that EPE be prohibited from holding its own securities, or those of the other PVNGS participants.

Q: Can your proposal be modified so that the fund is credited with an actual, rather than an imputed, return?

A: Yes. The fund can be credited with the actual after-tax return. This will result in lower decommissioning payments in the early years, since the investment return would be expected to contribute a larger fraction of the final fund balance. However, the ratepayers in the later years of the plant's life will be exposed to the risk that the balance will be smaller than expected (due to poor investment results, particularly in common stock capital gains), requiring larger future decommissioning assessments. This risk is balanced (before the fact) by the possibility of higher-than-expected returns, which would reduce or eliminate the need for decommissioning charges in the later years. This situation would create an intertemporal inequity, since future ratepayers would bear an additional risk burden so that current ratepayers could pay lower rates. The imputed return approach eliminates the intertemporal subsidy, by

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21. Insurance regulators become alarmed if the corresponding ratio for insurers falls below 1.5, but about half of that 50% buffer is required to cover variability in insurance claims: I have assumed that EPE will not generally be held accountable for early or expensive decommissioning, so the relevant ratio of assets to liabilities, based on the experience of insurers, is 1.25.

transferring both the investment risk and the return associated with that risk to the shareholders, who should see no change in their share price as a result. If the PSC elects to apply actual returns to the decommissioning fund, I would suggest that it reduce the intertemporal issues by instructing EPE to maintain a low-risk portfolio, with little if any common stock, and composed primarily of investment-grade tax-sheltered fixed-income securities (municipal bonds and preferred stock).

Q: Should EPE take any other actions with respect to decommissioning?

A: Yes. Due to the large remaining risks and uncertainties in nuclear decommissioning cost and timing, it would be highly desirable to establish a risk-sharing mechanism for decommissioning costs, consisting of either a commercial insurance program, an industry self-insurance pool, or a hybrid of the two. The extent and coverage of such a program would necessarily be the subject of negotiation between the participants, but it could reduce the risk to both ratepayers and shareholders from an especially expensive or premature decommissioning of one or more PVNGS units.[22] The potential

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22. The utility pool can not provide protection from a systematic risk, such as general utility over-optimism in projecting the useful life and decommissioning cost of nuclear units. These systematic problems can be addressed in the adjustments to the decommissioning fund over time. Since the adjustment of fund accrual cannot protect against non-systematic bad luck at PVNGS (the realm of insurance), the fund adjustment

advantages and problems of a utility self-insurance pool for this purpose are discussed in the Analysis and Inference report to the NRC, Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense (NUREG/CR-2370), which is attached as Appendix D to this testimony.

Q: In the event that EPE's cost recovery for its share of one or more of the PVNGS units is deferred, as through a phase-in or inventory arrangement, how should the decommissioning costs be treated?

A: The important point is that accumulation of the decommissioning fund must not be deferred excessively by such a ratemaking mechanism. If the Commission wishes to defer a certain amount of costs, it could either leave the decommissioning fund in rates and defer other cost items (especially return on investment), or it could require EPE to contribute to the fund (for the portion of the plant or cost for which cost recovery is deferred) and treat the contribution along with other deferred costs (e.g., essentially as AFUDC is treated in the PNM inventory process). If the deferral is the result of a negotiation (as was PNM's inventory), decommissioning can be treated in many

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mechanism and the insurance program would be complementary, rather than redundant.

ways, as part of balancing the overall costs and risks to the ratepayers and shareholders, so long as it is funded.

Q: How should the decommissioning costs be treated, in the event that EPE is denied cost recovery for all or part of its share of one or more of the PVNGS units is deferred?

A: If the disallowance is due to excessively high costs (too many dollars), due to construction mismanagement, there should be no effect on the funding of the decommissioning reserve: decommissioning is still a necessary cost to serve the ratepayers, and they should pay that cost. If the disallowance results from excessive capacity (too many megawatts), due to errors in power supply planning, conceptual consistency would require that the shareholders pay for decommissioning the part of the plant which was not needed by the customers. Depending on the size of the disallowance that EPE bears, the ability (and willingness) of the utility to fund the decommissioning reserve for disallowed plant, and the ability of the Commission to compel EPE to make contributions, it may be preferable to leave responsibility for the decommissioning fund with the ratepayers, and to increase the disallowance of other costs correspondingly.

8 - AN INTERIM PERFORMANCE STANDARD FOR PVNGS

Q: Is it reasonable for the PSC to impose a performance standard for Unit 1 of the PVNGS, simultaneous with commercial operation and the reflection of the unit's costs in rates?

A: Yes. The declaration of commercial operation should be prompted by the determination that the unit is available for normal dispatch and power production, and that the startup and testing phase is essentially over. The cost of the unit should be included in EPE's rates only when the unit is providing regular service to consumers (i.e., when it is fully "used and useful"). Hence, it is entirely appropriate for the PSC to expect that the unit will perform to some specified level once it is declared commercial and enters rates.

Q: How might performance standards be set?

A: There are a variety of possible performance standards, covering various performance measures (e.g., capacity factor, heat rate), based on various concepts of fairness, and implemented in a variety of ratemaking structures. Some of these options are discussed in my paper, "Power Plant Performance Standards: Some Introductory Principles," attached as Appendix E to this testimony.

Q: What performance standard would you recommend the PSC apply to EPE when PVNGS Unit 1 is declared to be in commercial operation?

A: I would recommend that a capacity factor standard be implemented: capacity factor is by far the most important measure of nuclear plant performance.[23] I would further recommend that the capacity factor standard be set initially at 68.4%, which is the capacity factor projected for PVNGS's first cycle of operation (that is, until the beginning of the first refueling outage) by the plant's lead utility, Arizona Public Service. It is my understanding that the 68% capacity factor projection has been utilized by EPE for a variety of purposes, including rate design and the estimation of the net rate effects of PVNGS on the EPE system. Since EPE apparently considers this projection to be accurate and unbiased, it can hardly argue that it is inappropriate to expect PVNGS to achieve that level of performance.

Q: How would you recommend that the PSC apply this performance target?

A: It would be appropriate to treat PVNGS Unit 1 on an interim basis as if it were performing at 68% capacity factor, regardless of how it actually performs. Thus, fuel cost recovery would exceed EPE's actual fuel costs if the unit

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23. Where the nuclear unit may cycle or follow load, as in the Pacific Northwest, "equivalent availability factor" is a more appropriate measure of performance.

exceeds 68% capacity factor, and would cover less than actual fuel costs if it falls short of 68% capacity factor.

Q: Do you have any other recommendations regarding performance standards for PVNGS?

A: Yes. I described my performance standard recommendations as interim measures for the initial year or so of Unit 1 operation. In the longer term, the PSC should initiate a proceeding to determine long-term performance standards for PVNGS, considering such issues as

- How should the target change over time, as the PVNGS units mature?
- Should any considerations, other than EPE's prior projections, be used in setting standards?
- Should all variations from the standard be borne by EPE's shareholders, or should some of the benefits and costs be shared with the ratepayers?
- What provisions should be made for exceptions to, or revisions of, the standards?
- How should the standard be applied and administered (e.g., should the standard be averaged over years and over units)?

I believe that these issues are too complex to consider within the current proceeding, especially given the possibility that PVNGS Unit 1 will soon enter service, requiring the PSC to reach conclusions on other issues in this case.

Q: Does this conclude your testimony?

A: Yes.

TABLE 1: REVENUE REQUIREMENT EFFECT OF $1 DOLLAR REDUCTION IN RATE BASE

Assumptions:

50% of Marginal Capital is equity at 15% return.

50% of Marginal Capital is debt at 12% return.

Net Income Tax Rate = 49.2%: Tax Multiplier = 1.97

Revenue Requirement Reduction for $1 dollar Rate Base Reduction:

1. Equity saved	$0.500	
2. Return on equity saved ([1]*15%)		$0.075
3. Taxes avoided due to reduced equity return ([2]*.97)		$0.073
4. Debt saved	$0.500	
5. Return on Debt saved ([4]*12%)		$0.060
6. Total reduction in revenue requirement		$0.208

TABLE 2: RETURN AND TAX RATE, EXTERNAL FUND BASE
PORTFOLIO CONSISTENT WITH EPE INTERNAL FUND

	EQUITY			DEBT	
% of Portfolio:			50%	50%	
	Dividends	Capital Gains	Total Equity	Debt	Average [3]
Gross Return	12.0%	3.0%	15.0%	12.0%	13.50%
Tax Rate [1]	6.9%	28.0%	11.12%	46.0%	26.62%
After-tax Return [2]	11.17%	2.16%	13.33%	6.48%	9.91%

Notes: 1. Tax rates on dividends, capital gains and debt are inputs; tax rate on total equity is calculated.

The tax rate on total equity is calculated from gross and after-tax return on total equity.

2. After-tax return is calculated as Gross Return * (1 - Tax Rate) for dividends, capital gains and debt.

After-tax return on total equity is the sum of the after tax returns on dividends and capital gains.

3. Average return is the average over total equity and debt. Average tax rate is calculated from average gross return and average after-tax return.

TABLE 3: REVENUE REQUIREMENTS FOR DECOMMISSIONING PALO VERDE UNIT NO. 1
EL PASO ELECTRIC COMPANY ($1000)

EXTERNAL FUND 13.5% (9.91% AFTER TAX)
TAX RATE 27%

Line No.	Year	Annuity Net Revenue Requirement	Interest	Decommissioning Expense	Fund Balance
1	1986	493	0	0	493
2	1987	493	49	0	1,034
3	1988	493	102	0	1,629
4	1989	493	161	0	2,283
5	1990	493	226	0	3,002
6	1991	493	297	0	3,792
7	1992	493	376	0	4,660
8	1993	493	462	0	5,614
9	1994	493	556	0	6,663
10	1995	493	660	0	7,816
11	1996	493	775	0	9,083
12	1997	493	900	0	10,476
13	1998	493	1,038	0	12,007
14	1999	493	1,190	0	13,689
15	2000	493	1,355	0	15,536
16	2001	493	1,540	0	17,570
17	2002	493	1,741	0	19,804
18	2003	493	1,962	0	22,259
19	2004	493	2,206	0	24,957
20	2005	493	2,473	0	27,922
21	2006	493	2,767	0	31,182
22	2007	493	3,090	0	34,764
23	2008	493	3,445	0	38,701
24	2009	493	3,835	0	43,029
25	2010	493	4,264	0	47,785
26	2011	493	4,735	0	53,013
27	2012	493	5,253	0	58,759
28	2013	493	5,823	0	65,073
29	2014	493	6,448	0	72,014
30	2015	493	7,136	0	79,642
31	2016	493	7,892	0	88,027
32	2017	493	8,723	0	97,243
33	2018	493	9,636	(1,338)	106,031
34	2019	493	10,507	(3,992)	113,039
35	2020	493	11,201	(29,199)	95,534
36	2021	0	9,465	(52,069)	52,932
37	2022	0	5,245	(43,540)	14,637
38	2023	0	1,450	(16,087)	(0)
39	TOTAL	17,240	128,965	(146,225)	
PV @	16.0%	3,062			

TABLE 4: REVENUE REQUIREMENTS FOR DECOMMISSIONING PALO VERDE UNIT NO. 1
THREE YEAR INCREASING STRAIGHT LINE METHOD
EL PASO ELECTRIC COMPANY ($1000)

TAX MULTIPLIER	1.97		
IMPUTED INTEREST RATE:	20.78%	ON INTERNAL FUND, from:	
Equity as % of Capital	50%	Equity Rate	15%
Debt as % of Capital	50%	Debt Rate	12%

Line No.	Year	Customer Charge	Decommissioning Fund Increase	Decommissioning Expense	Fund Balance	Net Revenue Required
1	1986	650	330	0	330	650
2	1987	650	330	0	660	581
3	1988	650	330	0	990	513
4	1989	1,320	670	0	1,660	1,114
5	1990	1,320	670	0	2,330	975
6	1991	1,320	670	0	3,000	836
7	1992	1,970	1,000	0	4,000	1,347
8	1993	1,970	1,000	0	5,000	1,139
9	1994	1,970	1,000	0	6,000	931
10	1995	2,630	1,335	0	7,335	1,384
11	1996	2,630	1,335	0	8,670	1,106
12	1997	2,630	1,335	0	10,005	829
13	1998	3,285	1,669	0	11,673	1,205
14	1999	3,285	1,668	0	13,340	860
15	2000	3,285	1,668	0	15,008	514
16	2001	3,940	2,000	0	17,008	922
17	2002	3,940	2,000	0	19,008	407
18	2003	3,940	2,000	0	21,008	(5)
19	2004	4,600	2,335	0	23,343	338
20	2005	4,600	2,335	0	25,678	(249)
21	2006	4,600	2,335	0	28,013	(725)
22	2007	5,255	2,668	0	30,680	(555)
23	2008	5,255	2,668	0	33,348	(1,119)
24	2009	5,255	2,668	0	36,015	(1,673)
25	2010	5,915	3,003	0	39,019	(1,557)
26	2011	5,915	3,003	0	42,020	(2,134)
27	2012	5,915	3,003	0	45,023	(2,815)
28	2013	6,565	3,332	0	48,355	(2,793)
29	2014	6,565	3,332	0	51,688	(3,491)
30	2015	6,565	3,332	0	55,020	(4,173)
31	2016	7,230	3,670	0	58,690	(4,202)
32	2017	7,230	3,670	0	62,360	(4,962)
33	2018	7,230	3,670	(1,338)	65,351	(5,725)
34	2019	8,070	4,098	(3,992)	67,421	(5,507)
35	2020	8,075	4,099	(29,199)	56,698	(5,932)
36	2021	0	0	(52,069)	30,258	(11,779)
37	2022	0	0	(43,540)	8,166	(6,288)
38	2023	0	0	(16,087)	(0)	(1,695)
39	TOTAL	146,225		(146,225)		(52,006)
PV @	16.0%	11,094				4232

TABLE 5: REVENUE REQUIREMENTS FOR DECOMMISSIONING PALO VERDE UNIT NO. 1
EL PASO ELECTRIC COMPANY ($1000)

EXTERNAL FUND	13.5%	(9.91% AFTER TAX)
TAX RATE	27%	

Line No.	Year	Annuity Net Revenue Requirement [1]	Interest	Decommissioning Expense	Fund Balance
1	1986	580	0	0	580
2	1987	580	57	0	1,217
3	1988	580	121	0	1,918
4	1989	1,000	190	0	3,108
5	1990	1,000	308	0	4,416
6	1991	1,000	438	0	5,854
7	1992	1,000	580	0	7,434
8	1993	1,000	737	0	9,170
9	1994	1,000	909	0	11,079
10	1995	1,000	1,098	0	13,177
11	1996	1,000	1,306	0	15,483
12	1997	1,000	1,534	0	18,017
13	1998	1,000	1,785	0	20,802
14	1999	1,000	2,061	0	23,863
15	2000	1,000	2,365	0	27,228
16	2001	1,000	2,699	0	30,926
17	2002	(1,094)	3,064	0	32,896
18	2003	(1,094)	3,260	0	35,061
19	2004	(1,094)	3,474	0	37,441
20	2005	(1,094)	3,710	0	40,057
21	2006	(1,094)	3,968	0	42,931
22	2007	(1,094)	4,254	0	46,091
23	2008	(1,094)	4,567	0	49,563
24	2009	(1,094)	4,911	0	53,380
25	2010	(1,094)	5,289	0	57,575
26	2011	(1,094)	5,705	0	62,186
27	2012	(1,094)	6,162	0	67,253
28	2013	(1,094)	6,664	0	72,823
29	2014	(1,094)	7,216	0	78,945
30	2015	(1,094)	7,823	0	85,673
31	2016	(1,094)	8,489	0	93,063
32	2017	(1,094)	9,226	0	101,195
33	2018	(1,094)	10,027	(1,338)	108,790
34	2019	(1,094)	10,780	(3,992)	114,484
35	2020	(1,094)	11,344	(29,199)	95,534
36	2021	0	9,466	(52,069)	52,932
37	2022	0	5,245	(43,540)	14,637
38	2023	0	1,450	(16,087)	0
39	TOTAL	(6,055)	152,280	(146,225)	
PV @	16.0%	4,127			

Note: [1] Annuity for years 1986-88 and 1989-2001 are selected to approximate Net Revenue Requirement in Table 4.

TABLE 6: COMPARISON OF NET REVENUE REQUIREMENTS

Line No. ----	Year -----	Net Revenue EPE Internal Fund ----[1]----	Requirement Levelized External Fund -----[2]-----	Accelerated External Fund -----[3]-----
1	1986	650	493	590
2	1987	581	493	580
3	1988	513	493	580
4	1989	1,114	493	1,000
5	1990	975	493	1,000
6	1991	836	493	1,000
7	1992	1,347	493	1,000
8	1993	1,139	493	1,000
9	1994	931	493	1,000
10	1995	1,384	493	1,000
11	1996	1,106	493	1,000
12	1997	829	493	1,000
13	1998	1,206	493	1,000
14	1999	860	493	1,000
15	2000	514	493	1,000
16	2001	822	493	1,000
17	2002	407	493	(1,094)
18	2003	(9)	493	(1,094)
19	2004	335	493	(1,094)
20	2005	(249)	493	(1,094)
21	2006	(739)	493	(1,094)
22	2007	(585)	493	(1,094)
23	2008	(1,119)	493	(1,094)
24	2009	(1,673)	493	(1,094)
25	2010	(1,587)	493	(1,094)
26	2011	(2,151)	493	(1,094)
27	2012	(2,815)	493	(1,094)
28	2013	(2,782)	493	(1,094)
29	2014	(3,481)	493	(1,094)
30	2015	(4,173)	493	(1,094)
31	2016	(4,200)	493	(1,094)
32	2017	(4,963)	493	(1,094)
33	2018	(5,725)	493	(1,094)
34	2019	(5,507)	493	(1,094)
35	2020	(5,932)	493	(1,094)
36	2021	(11,779)	0	0
37	2022	(6,398)	0	0
38	2023	(1,696)	0	0
39				
40	Total	(52,005)	17,240	(6,055)
41	PV at 16.0%	4,232	3,062	4,127

Notes: 1. From Table 4.
2. From Table 3.
3. From Table 5.

TABLE 7: COMPARISON OF DECOMMISSIONING FUND BALANCES AND REQUIREMENTS

		FUND BALANCES			Cash Requirements Normal Decommissioning at EPE Cost	
Line No.	Year	EPE Internal Fund [1]	Levelized External Fund [2]	Accelerated External Fund [3]	Tax-affected [4]	Total Cost [5]
1	1986	330	493	580	9,546	18,806
2	1987	660	1,034	1,217	10,119	19,935
3	1988	990	1,629	1,918	10,726	21,131
4	1989	1,660	2,283	3,109	11,370	22,399
5	1990	2,330	3,002	4,416	12,052	23,742
6	1991	3,000	3,792	5,854	12,775	25,167
7	1992	4,000	4,660	7,434	13,542	26,677
8	1993	5,000	5,614	9,170	14,354	28,278
9	1994	6,000	6,663	11,079	15,215	29,974
10	1995	7,335	7,816	13,177	16,128	31,773
11	1996	8,670	9,083	15,483	17,095	33,679
12	1997	10,005	10,476	18,017	18,122	35,700
13	1998	11,673	12,007	20,802	19,209	37,842
14	1999	13,340	13,689	23,863	20,362	40,112
15	2000	15,008	15,536	27,226	21,583	42,519
16	2001	17,008	17,570	30,926	22,878	45,070
17	2002	19,008	19,804	32,895	24,251	47,775
18	2003	21,008	22,259	35,061	25,706	50,641
19	2004	23,343	24,957	37,441	27,248	53,679
20	2005	25,678	27,922	40,057	28,376	55,900
21	2006	28,013	31,182	42,931	30,615	60,314
22	2007	30,680	34,764	46,091	32,453	63,933
23	2008	33,348	38,701	48,583	34,401	67,769
24	2009	36,015	43,025	52,380	36,465	71,835
25	2010	39,018	47,785	57,575	38,652	75,145
26	2011	42,020	53,013	62,185	40,972	80,714
27	2012	45,023	58,758	67,252	43,430	85,557
28	2013	48,355	65,073	72,823	46,036	90,690
29	2014	51,689	72,014	78,945	48,798	96,132
30	2015	55,020	79,642	85,577	51,726	101,900
31	2016	58,690	88,027	93,063	54,829	108,014
32	2017	62,360	97,242	101,195	58,119	114,494
33	2018	65,351	106,032	106,790	61,606	121,364
34	2019	67,421	113,039	114,484	64,582	127,227
35	2020	56,698	95,534	95,534	66,308	130,627
36	2021	30,268	52,932	52,932		
37	2022	8,155	14,637	14,637		
38	2023	(0)	(0)	0		

Notes:
1. From Table 4.
2. From Table 3.
3. From Table 5.
4. From Johnson, Exhibit WJJ-4, Column 10.
5. Column 5 multiplied by 1.97 (tax-multiplier)

TABLE 8:

Expected Return:	15	
Beta of each stock:	1	
SD of market return:	20	percentage points
SD of nonmarket return:	30.55	percentage points

Number of Stocks	Total Standard Deviation		Lower End of 95% Confidence Interval after t Years		
		t=	1	10	20
1	36.51		-56.57%	-7.83%	-1.00%
2	29.44		-42.70%	-3.25%	2.10%
3	26.67		-37.27%	-1.53%	3.31%
4	25.17		-34.33%	-0.60%	3.97%
5	24.22		-32.47%	-0.01%	4.38%
6	23.57		-31.20%	0.39%	4.67%
7	23.09		-30.26%	0.69%	4.88%
8	22.73		-29.55%	0.91%	5.04%
9	22.44		-28.99%	1.09%	5.16%
10	22.21		-28.53%	1.23%	5.27%
15	21.50		-27.14%	1.67%	5.59%
20	21.13		-26.42%	1.90%	5.74%
25	20.91		-25.99%	2.04%	5.83%
30	20.76		-25.70%	2.13%	5.90%
35	20.66		-25.49%	2.20%	5.95%
40	20.58		-25.33%	2.25%	5.99%
45	20.51		-25.20%	2.29%	6.01%
50	20.46		-25.10%	2.32%	5.03%
55	20.42		-25.02%	2.34%	6.05%
60	20.39		-24.95%	2.37%	6.07%
65	20.36		-24.90%	2.38%	6.08%
70	20.33		-24.85%	2.40%	6.09%
75	20.31		-24.81%	2.41%	6.10%
80	20.29		-24.77%	2.42%	6.11%
85	20.27		-24.73%	2.43%	6.12%
90	20.26		-24.70%	2.44%	5.12%
95	20.24		-24.68%	2.45%	6.13%
100	20.23		-24.65%	2.46%	6.13%
1000000	20.00		-24.20%	2.60%	6.23%

TABLE 9: ADJUSTMENT CASE I -- RATE SHOCK MITIGATION
REVENUE REQUIREMENTS FOR DECOMMISSIONING PALO VERDE UNIT NO. 1
EL PASO ELECTRIC COMPANY ($1000)

EXTERNAL FUND 13.5% (9.91% AFTER TAX)
TAX RATE 27%

Line No.	Year	Annuity Net Revenue Requirement [i]	Interest	Decommissioning Expense	Fund Balance
1	1986	600	0	0	600
2	1987	600	59	0	1,259
3	1988	600	125	0	1,984
4	1989	600	197	0	2,781
5	1990	600	276	0	3,656
6	1991	600	362	0	4,619
7	1992	600	458	0	5,676
8	1993	600	562	0	6,839
9	1994	600	678	0	8,117
10	1995	1,607	804	0	10,528
11	1996	1,607	1,043	0	13,177
12	1997	1,607	1,306	0	16,090
13	1998	1,607	1,594	0	19,291
14	1999	1,607	1,912	0	22,809
15	2000	1,607	2,260	0	26,676
16	2001	1,607	2,643	0	30,926
17	2002	(1,094)	3,064	0	32,896
18	2003	(1,094)	3,260	0	35,062
19	2004	(1,094)	3,474	0	37,442
20	2005	(1,094)	3,710	0	40,058
21	2006	(1,094)	3,969	0	42,934
22	2007	(1,094)	4,254	0	46,094
23	2008	(1,094)	4,567	0	49,568
24	2009	(1,094)	4,912	0	53,386
25	2010	(1,094)	5,290	0	57,582
26	2011	(1,094)	5,706	0	62,193
27	2012	(1,094)	6,163	0	67,262
28	2013	(1,094)	6,665	0	72,833
29	2014	(1,094)	7,217	0	78,956
30	2015	(1,094)	7,824	0	85,686
31	2016	(1,094)	8,491	0	93,082
32	2017	(1,094)	9,224	0	101,212
33	2018	(1,094)	10,029	(1,338)	108,809
34	2019	(1,094)	10,782	(3,992)	114,505
35	2020	(1,094)	11,346	(29,199)	95,558
36	2021	0	9,469	(52,069)	52,958
37	2022	0	5,248	(43,540)	14,666
38	2023	0	1,453	(16,087)	32
39	TOTAL	(4,139)	150,396	(146,225)	
PV @	16.0%	3,872			

TABLE 10: ADJUSTMENT CASE II -- REVISED USEFUL LIFE
REVENUE REQUIREMENTS FOR DECOMMISSIONING PALO VERDE UNIT NO. 1
EL PASO ELECTRIC COMPANY ($1000)

EXTERNAL FUND 13.5% (9.91% AFTER TAX)
TAX RATE 27%

Line No.	Year	Annuity Net Revenue Requirement [1]	Interest	Decommissioning Expense	Fund Balance
1	1986	600	0	0	600
2	1987	600	59	0	1,259
3	1988	600	125	0	1,984
4	1989	1,000	197	0	3,181
5	1990	1,000	315	0	4,496
6	1991	1,000	446	0	5,942
7	1992	1,000	589	0	7,530
8	1993	1,000	746	0	9,277
9	1994	1,000	919	0	11,196
10	1995	711	1,109	0	13,017
11	1996	711	1,290	0	15,018
12	1997	711	1,488	0	17,217
13	1998	711	1,705	0	19,635
14	1999	711	1,946	0	22,292
15	2000	711	2,209	0	25,212
16	2001	711	2,498	0	28,422
17	2002	711	2,816	0	31,950
18	2003	711	3,166	0	35,827
19	2004	711	3,550	0	40,089
20	2005	711	3,972	0	44,773
21	2006	711	4,437	0	49,921
22	2007	711	4,947	0	55,579
23	2008	711	5,507	0	61,795
24	2009	711	6,124	0	68,633
25	2010	711	6,801	0	76,145

Note: [1] Annuity for years 1995-2010 is selected to approximate a Fund Balance of $76,145,000 in year 2010.

TABLE 11: ADJUSTMENT CASE III -- INCREASED COST PROJECTION
REVENUE REQUIREMENTS FOR DECOMMISSIONING PALO VERDE UNIT NO. 1
EL PASO ELECTRIC COMPANY ($1000)

EXTERNAL FUND 13.5% (9.91% AFTER TAX)
TAX RATE 27%

Line No.	Year	Annuity Net Revenue Requirement [1]	Interest	Decommissioning Expense	Fund Balance
1	1986	600	0	0	600
2	1987	600	59	0	1,259
3	1988	600	125	0	1,984
4	1989	1,200	197	0	3,381
5	1990	1,200	335	0	4,915
6	1991	1,200	487	0	6,603
7	1992	1,800	654	0	9,057
8	1993	1,800	897	0	11,755
9	1994	1,800	1,165	0	14,720
10	1995	2,400	1,459	0	18,578
11	1996	2,400	1,841	0	22,819
12	1997	2,400	2,261	0	27,480
13	1998	3,000	2,723	0	33,203
14	1999	3,000	3,290	0	39,493
15	2000	3,000	3,913	0	46,407
16	2001	3,600	4,599	0	54,605
17	2002	3,600	5,41[illegible]	0	63,616
18	2003	3,600	6,304	0	73,520
19	2004	4,200	7,285	0	85,005
20	2005	4,200	8,423	0	97,628
21	2006	4,200	9,674	0	111,502
22	2007	4,800	11,048	0	127,350
23	2008	4,800	12,619	0	144,770
24	2009	4,800	14,345	0	163,915
25	2010	5,400	16,242	0	185,557
26	2011	5,400	18,357	0	209,344
27	2012	5,400	20,744	0	235,488
28	2013	6,000	23,334	0	264,822
29	2014	6,000	26,241	0	297,064
30	2015	6,000	29,436	0	332,502
31	2016	6,600	32,947	0	372,047
32	2017	6,600	36,366	0	415,313
33	2018	6,600	41,172	(5,682)	457,404
34	2019	7,200	45,324	(17,550)	492,373
35	2020	7,200	48,790	(129,368)	420,000
36	2021	0	41,619	(228,911)	232,707
37	2022	0	23,059	(191,415)	64,351
38	2023	0	6,377	(70,723)	5
39	TOTAL	133,200	509,654	(642,849)	
PV @	16.0%	10,136			

Note: [1] Annuity for years 1995-2010 is selected to approximate a Fund Balance of $76,145,000 in year 2010.
[2] EPE estimated Decommisioning Expense increased by a factor of 4.3963.

TABLE 12: ANNUAL FUND BALANCES -- BASE AND ADJUSTMENT CASES I-III
DECOMMISSIONING PALO VERDE UNIT NO. 1
EL PASO ELECTRIC COMPANY ($1000)

EXTERNAL FUND 13.5% (9.91% AFTER TAX)
TAX RATE 27%

		ANNUAL FUND BALANCES			
Line No.	Year	Base Case	Adjustment Case I	Adjustment Case II	Adjustment Case III
1	1986	580	600	600	600
2	1987	1,217	1,259	1,259	1,259
3	1988	1,918	1,984	1,984	1,984
4	1989	3,108	2,781	3,181	3,381
5	1990	4,416	3,656	4,496	4,916
6	1991	5,854	4,619	5,942	6,603
7	1992	7,434	5,676	7,530	9,057
8	1993	9,170	6,839	9,277	11,755
9	1994	11,079	8,117	11,196	14,720
10	1995	13,177	10,528	13,017	18,578
11	1996	15,483	13,177	15,018	22,819
12	1997	18,017	16,090	17,217	27,480
13	1998	20,802	19,291	19,635	33,203
14	1999	23,863	22,809	22,292	39,493
15	2000	27,228	26,676	25,212	46,407
16	2001	30,926	30,926	28,422	54,605
17	2002	32,896	32,896	31,950	63,515
18	2003	35,051	35,062	35,827	73,510
19	2004	37,441	37,442	40,089	85,005
20	2005	40,057	40,059	44,773	97,633
21	2006	42,931	42,934	49,921	111,503
22	2007	46,091	46,094	55,579	127,352
23	2008	49,563	49,565	61,798	144,770
24	2009	53,380	53,396	68,633	163,945
25	2010	57,575	57,582	76,145	185,557
26	2011	62,186	62,193		209,344
27	2012	67,253	67,262		235,493
28	2013	72,823	72,838		264,833
29	2014	78,945	78,955		297,064
30	2015	85,673	85,686		332,500
31	2016	93,068	93,082		372,047
32	2017	101,195	101,212		415,513
33	2018	108,790	108,909		457,404
34	2019	114,464	114,505		493,373
35	2020	95,534	95,558		420,000
36	2021	52,932	52,958		232,707
37	2022	14,637	14,665		64,351
38	2023	0	32		5

TABLE 13: Implicit Tax Rates on Municipal Bonds

APRIL 1985	Yields (%)				Implicit Tax Rates Municipals Yields vs:		
Rating (1)	Muni. (2)	Ind. (3)	Util. (4)	Comp. (5)	Industrials (6)	Utilities (7)	Composite (8)
Aaa	8.95%	11.67%	12.77%	12.23%	23.3%	29.9%	26.8%
Aa	9.26%	12.22%	13.17%	12.69%	24.2%	29.7%	27.0%
A	9.55%	12.71%	13.61%	13.14%	24.9%	29.8%	27.3%
Baa	9.95%	12.90%	14.11%	13.51%	22.9%	29.5%	26.4%
Average	9.43%	12.38%	13.42%	12.89%	23.8%	29.7%	26.9%

MAY 1985							
Aaa	8.52%	11.26%	12.18%	11.72%	24.3%	30.0%	27.3%
Aa	8.88%	11.95%	12.65%	12.30%	25.7%	29.8%	27.8%
A	9.14%	12.28%	13.12%	12.70%	25.6%	30.3%	28.0%
Baa	9.54%	12.68%	13.62%	13.15%	24.8%	30.0%	27.5%
Average	9.02%	12.04%	12.89%	12.47%	25.1%	30.0%	27.6%

JUNE 1985							
Aaa	8.24%	10.71%	11.17%	10.94%	23.1%	26.2%	24.7%
Aa	8.39%	11.24%	11.68%	11.46%	25.4%	28.2%	26.8%
A	8.60%	11.83%	12.13%	11.98%	27.3%	29.1%	28.2%
Baa	9.02%	12.14%	12.66%	12.40%	25.7%	28.8%	27.3%
Average	8.56%	11.48%	11.91%	11.70%	25.4%	28.1%	26.7%

NOTES:

(1) Definition: Bond rating is a way of classifying bonds according to the risk of the investment.

Source: Moody's Bond Record and Bond Survey.

(2) Definition: Monthly yields on Municipal bonds.

Source: "Municipal Bond Yield Averages" table in Moody's Bond Survey, 14 June and 29 July 1985.

(3) Definition: Monthly yields on Industrial bonds.

Source: Data is from corporate monthly bond yield averages used in Moody's Bond Record: "Corporate bond averages are based on yields to maturity on selected long-term bonds." Long-term municipal bond monthly yield averages are from the back cover of Moody's Bond Survey.

(4) Definition: Monthly yields on Public Utility bonds.

Source: Same as Column (3).

(5) Definition: Monthly composite yields by ratings.

Source: Same as Column (3). Composite yields came from the columns labeled "Corporate by Ratings."

(6) Definition: The implicit tax rate of municipal bonds as compared only to industrial bonds.

Source: (6)=1-[(2)/(3)]

(7) Definition: The implicit tax rate of municipal bonds as compared only to utility bonds.

Source: (7)=1-[(2)/(4)]

(8) Definition: The implicit tax rate of municipal bonds as compared to Moody's Corporate Bond Index.

Source: (8)=1-[(2)/(5)]

Note: "Composite" is the Moody's overall CORPORATE BOND INDEX as described in Moody's Bond Survey.

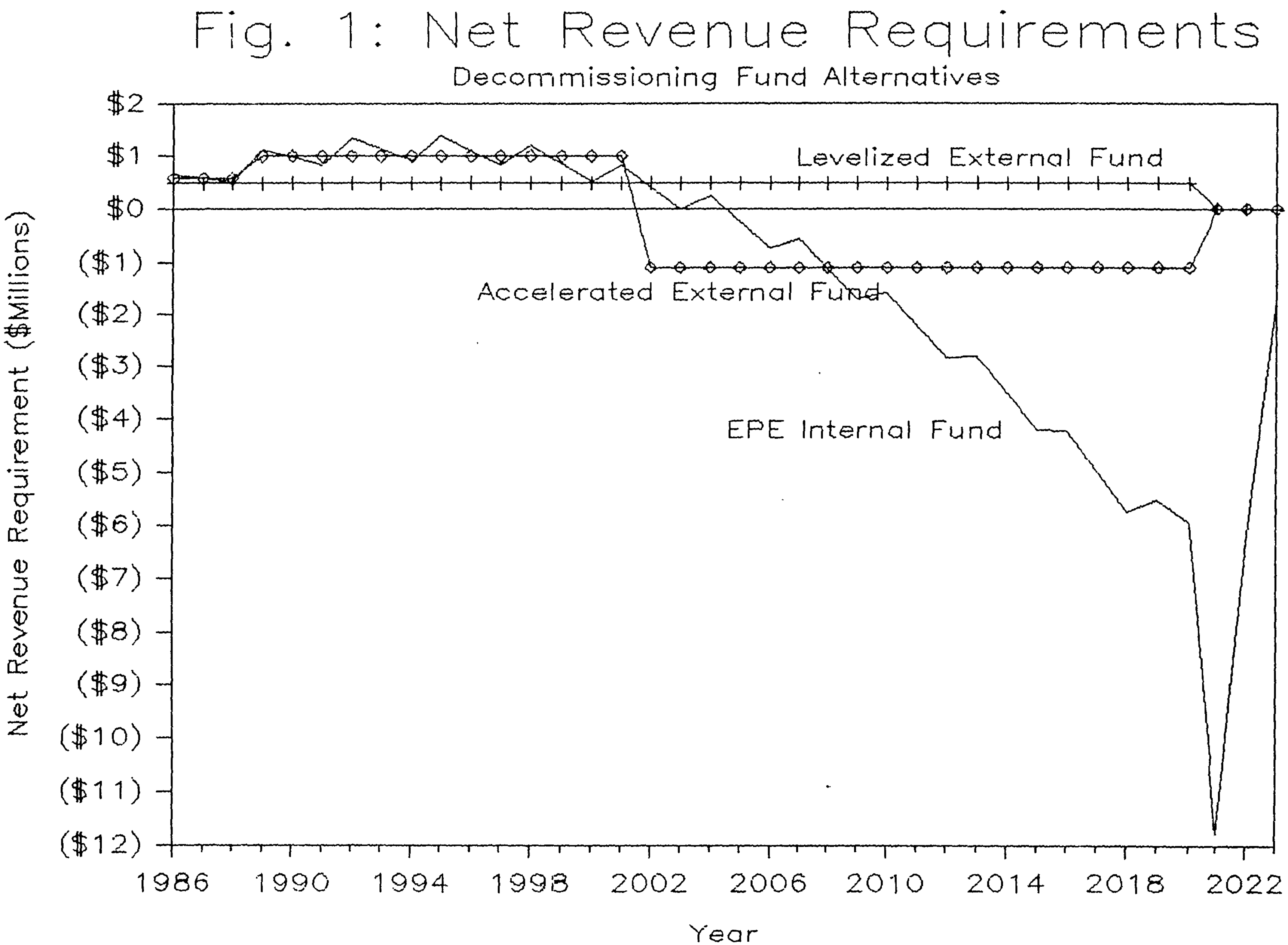


Fig. 1: Net Revenue Requirements
Decommissioning Fund Alternatives
$2
$1
$0
($1)
($2)
($3)
($4)
($5)
($6)
($7)
($8)
($9)
($10)
($11)
($12)
Net Revenue Requirement ($Millions)
Levelized External Fund
Accelerated External Fund
EPE Internal Fund
1986
1990
1994
1998
2002
2006
2010
2014
2018
2022
Year

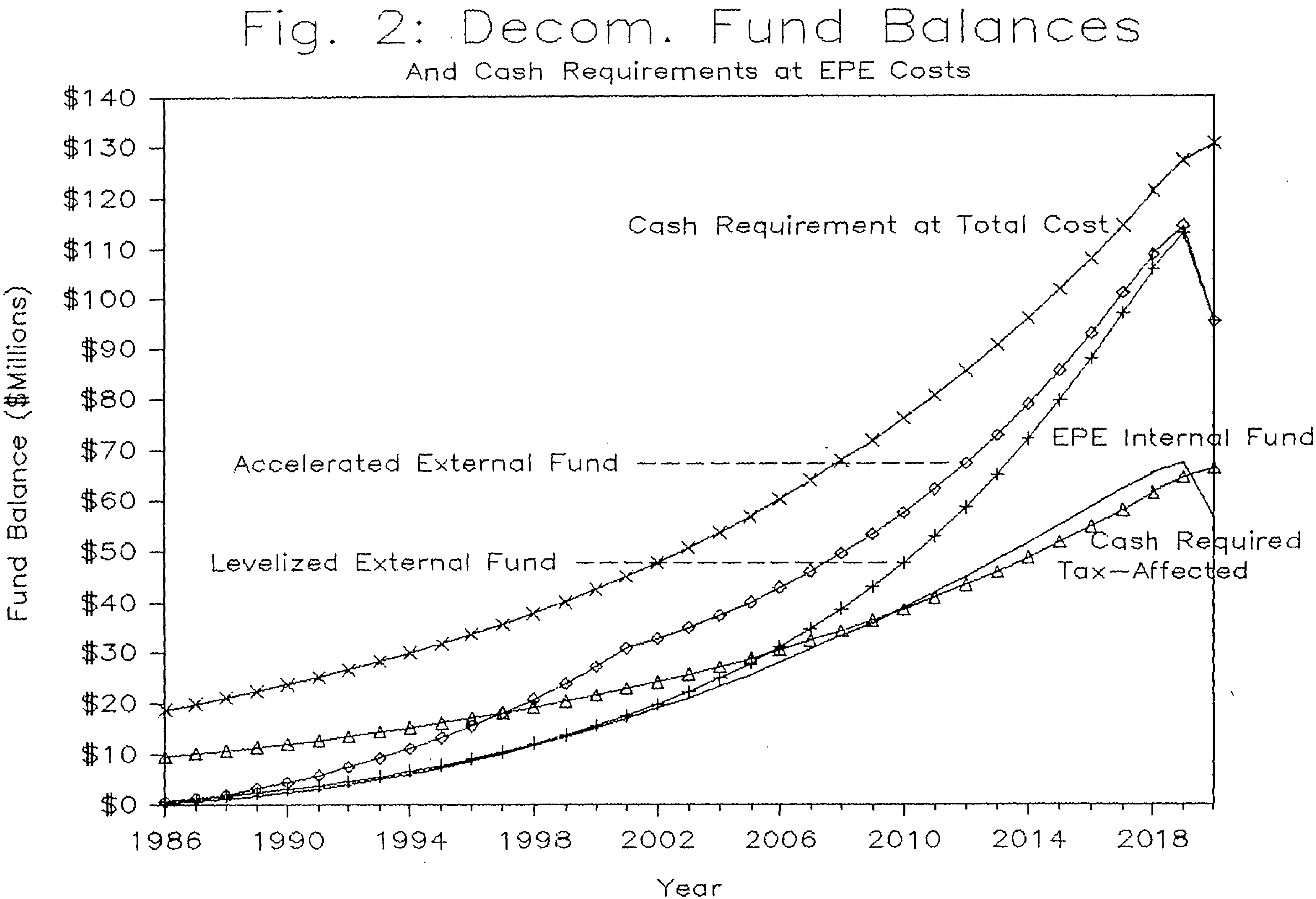
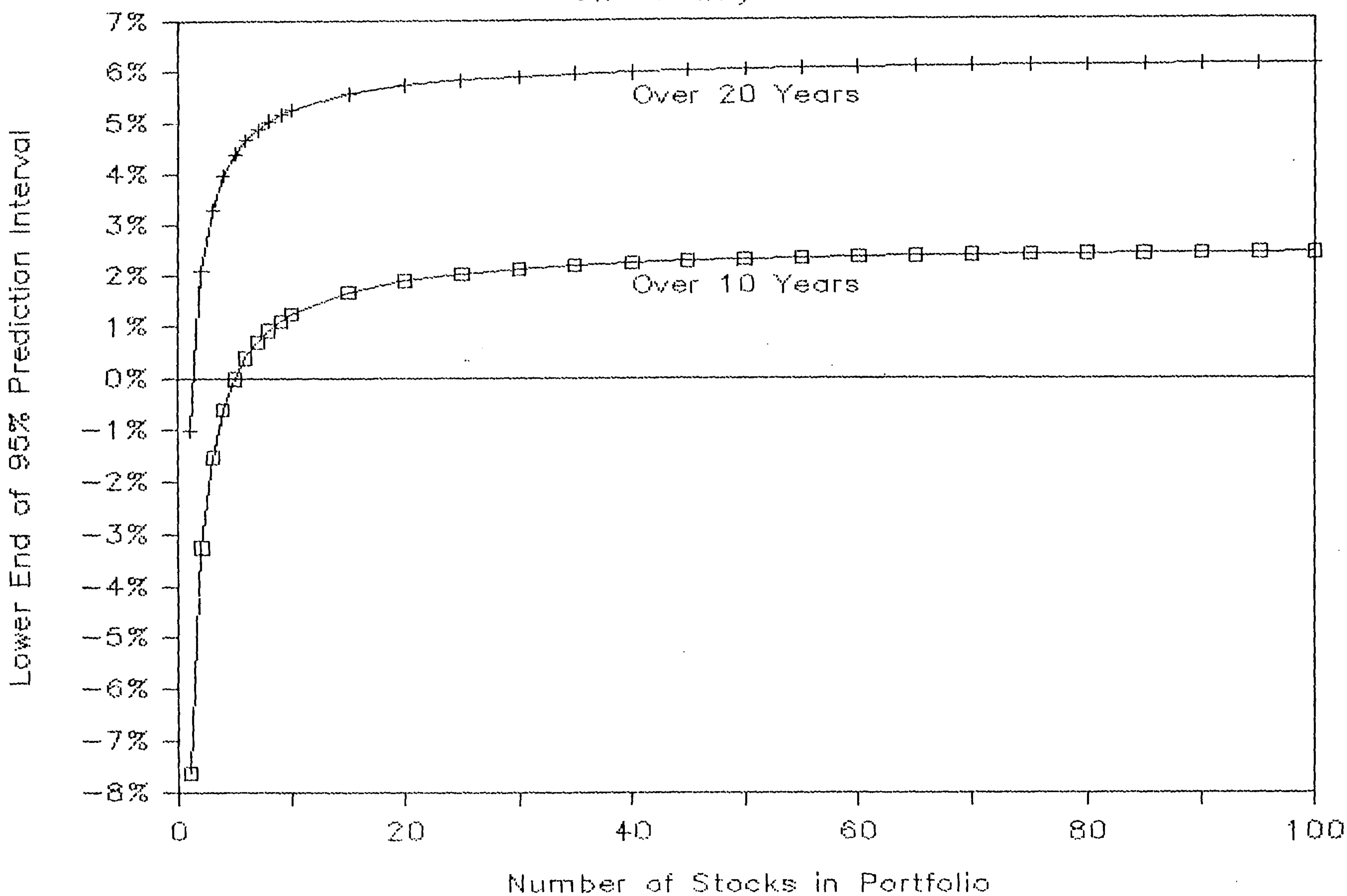


Fig. 2: Decom. Fund Balances
And Cash Requirements at EPE Costs
Fund Balance ($Millions)
$140
$130
$120
$110
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
1986
1990
1994
1998
2002
2006
2010
2014
2018
Year
Cash Requirement at Total Cost
EPE Internal Fund
Accelerated External Fund
Levelized External Fund
Cash Required
Tax-Affected

Figure 3: Effect of Diversification

On Security of Return



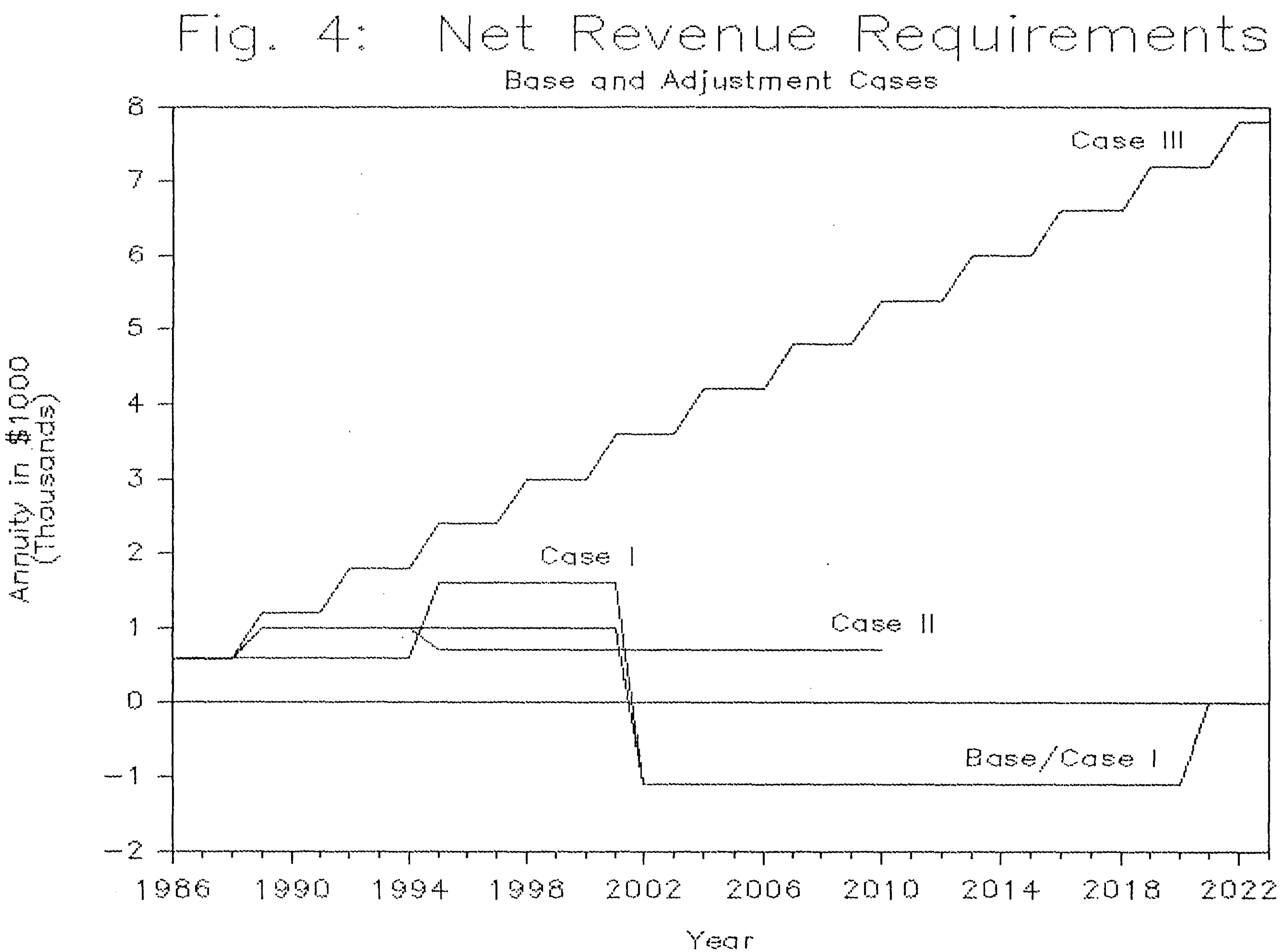
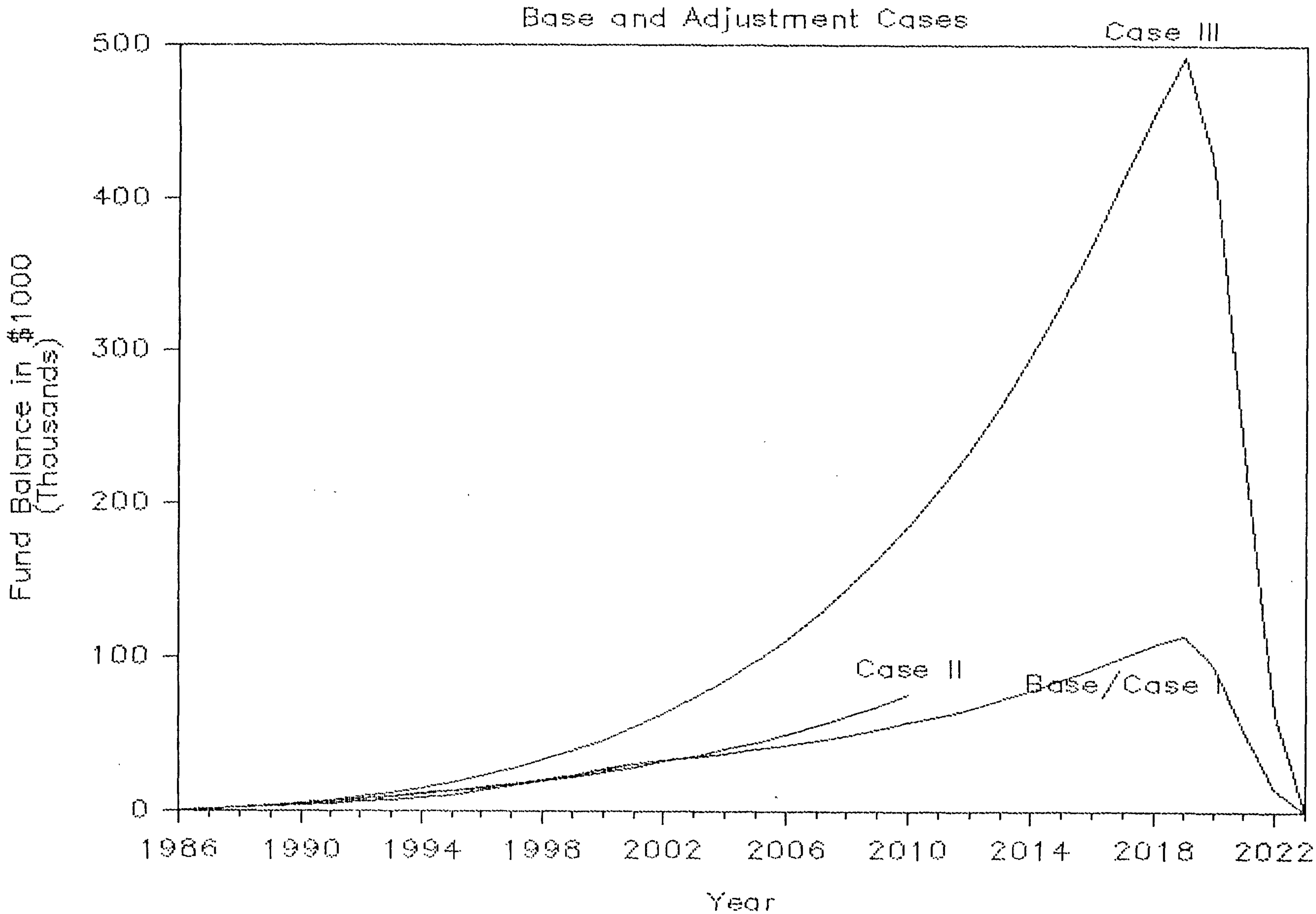


Fig. 4: Net Revenue Requirements
Base and Adjustment Cases
Annuity in $1000
(Thousands)
8
7
6
5
4
3
2
1
0
−1
−2
Case III
Case I
Case II
Base/Case I
1986
1990
1994
1998
2002
2006
2010
2014
2018
2022
Year

Fig. 5: Decom. Fund Balances



APPENDIX A:

RESUME OF PAUL CHERNICK

PAUL L. CHERNICK

Analysis and Inference, Inc.
10 Post Office Square
Boston, Massachusetts 02109
(617) 542-0611

PROFESSIONAL EXPERIENCE

Research Associate, Analysis and Inference, Inc.

May, 1981 - present (Consultant, 1980-1981)

Research, consulting and testimony in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions.

Consulted on utility rate design issues including small power producer rates; retail natural gas rates; public agency electric rates; and comprehensive electric rate design for a regional power agency. Developed electricity cost allocations between customer classes.

Reviewed district heating system efficiency. Proposed power plant performance standards. Analyzed auto insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

Utility Rate Analyst, Massachusetts Attorney General
December, 1977 - May, 1981

Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies.

Topics included: demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power pool operations, nuclear power cost projections, power plant cost-benefit analysis, energy conservation and alternative energy development.

EDUCATION

S.M., Technology and Policy Program, Massachusetts Institute of Technology, February, 1978

S.B., Civil Engineering Department, Massachusetts Institute of Technology, June, 1974

HONORARY SOCIETIES

Chi Epsilon (Civil Engineering)
Tau Beta Pi (Engineering)
Sigma Xi (Research)

OTHER HONORS

Institute Award, Institute of Public Utilities, 1981

PUBLICATIONS

Eden, P., Fairley, W., Aller, C., Vencill, C., Meyer, B., and Chernick, P., "Forensic Economics and Statistics: An Introduction to the Current State of the Art," The Practical Lawyer, June 1, 1985, pp. 25-36.

Chernick, P., "Power Plant Performance Standards: Some Introductory Principles," Public Utilities Fortnightly, April 18, 1985, pp. 29-33.

Chernick, P., "Opening the Utility Market to Conservation: A Competitive Approach," in Energy Industries in Transition, 1985-2000, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November, 1984, pp. 1133-1145.

Meyer, M., Chernick, P., and Fairley, W., "Insurance Market Assessment of Technological Risks," presented at the Annual Meeting of the Society of Risk Analysis, Knoxville, Tennessee, October, 1984.

Chernick, P., "Revenue Stability Target Ratemaking," Public Utilities Fortnightly, February 17, 1983, pp. 35-39.

Capacity/Energy Allocations for Generation and Transmission Plant," in Award Papers in Public Utility Economics and Regulation, Institute for Public Utilities, Michigan State University, 1982.

Chernick, P., Fairley, W., Meyer, M., and Scharff, L., Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December, 1981.

Chernick, P., Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September, 1977.

PRESENTATIONS

New England Utility Rate Forum; Plymouth, Massachusetts, October 11, 1985; "Lessons from Massachusetts on Long Term Rate for QF's"

National Association of State Utility Consumer Advocates; Williams Massachusetts, August 13, 1984; "Power Plant Performance".

National Conference of State Legislatures; Boston, Massachusetts, August 6, 1984; "Utility Rate Shock"

National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C.; June 20, 1984; "Review and Modification of Regulatory and Rate Making Policy".

Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management, Detroit, Michigan, May 27, 1983. "Insurance Market Assessment of Technological Risks".

EXPERT TESTIMONY

In each entry, the following information is presented in order: jurisdiction and docket number; title of case; client; date testimony filed; and subject matter covered. Abbreviations of jurisdictions include: MDPU (Massachusetts Department of Public Utilities); MEFSC (Massachusetts Energy Facilities Siting Council); PSC (Public Service Commission); and PUC (Public Utilities Commission).

1. MEFSC 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12, 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with S.C. Geller.

2. MEFSC 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29, 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. MEFSC 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27, 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. MDPU 19494, Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Reviewed numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. MDPU 19494, Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29, 1979.

   Review of the Oak Ridge National Laboratory and the NEPOOL demand forecast models; cost-effectiveness of oil deplacement; nuclear economics. Joint testimony with S.C. Geller.

7. MDPU 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4, 1979.

   Critiquing of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. MDPU 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23, 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares, Seabrook power costs, including construction cost, completion date, capacity factor, O & M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal prevention.

9. MDPU 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2, 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. MDPU 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16, 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. MEFSC 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16, 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. MDPU 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19, 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. Texas PUC 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25, 1980.

    Inter-class revenue allocations, including production plant in service, O & M, CWIP, nuclear fuel in progress, amortization of cancelled plant residential rate design; interrruptible rates; off-peak rates. Joint testimony with M.B. Meyer.

14. MEFSC 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5, 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. MDPU 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12, 1980.

    Conservation as an energy source; advantages of per-kwh allocation over per-customer month allocation.

16. MDPU 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26, 1981 and February 13, 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QF's in specific areas; wheeling; standardization of fees and charges.

17. MEFSC 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12, 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecast and wholesale forecast.

18. MDPU 558; Western Massachsuetts Electric Company Rate Case; Massachusetts Attorney General; May, 1981.

    Rate design; declinig blocks, marginal cost, conservation impacts, promotional rates; conservation: terms and conditions limiting renewables, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. MDPU 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7, 1982.

Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. DCPSC FC785; Potomac Electric Power Rate Case: DC People's Counsel; July 29, 1982.

Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O & M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. NHPUC DE81-312; Public Service of New Hampshire - Supply and Demand; Conservation Law Foundation, et al., October 8, 1982.

Conservation program design, ratemaking, and effectiveness. Cost of nuclear power, including construction cost and duration, capacity factor, O & M, replacements, insurance, and decommissioning.

22. Massachusetts Division of Insurance; Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1982.

Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. Illinois Commerce Commission 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15, 1982.

Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O & M, capital additions, useful life, capacity factor), risks, discount rates, evaluation techniques.

24. New Mexico Public Service Commission 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10, 1983.

Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking.

25. Connecticut Public Utility Control Authority 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17, 1983.

Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O & M, replacements, insurance, and decommissioning.

26. MDPU 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15, 1983.

Critiquing of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. Massachusetts Division of Insurance; Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1983.

Profit margin calculations, including methodology, interest rates, surplus flow, tax rates, and recognition of risk.

28. Connecticut Public Utility Control Authority 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3, 1983.

Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand U.S. energy charges.

29. MEFSC 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14, 1983, Rebuttal, February 2, 1984.

Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. Michigan PSC U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21, 1984.

Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. MDPU 84-25; Western Massachusetts Electric Company Rate Case; Mass. Attorney General; April 6, 1984.

Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. MDPU 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13, 1984.

Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. Michigan PSC U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16, 1984.

Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative proposals.

34. FERC ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27, 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. Maine PUC 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13, 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. MDPU 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6, 1984.

Prudence of Fitchburg and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. Pennsylvania PUC R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November, 1984.

Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. NHPUC 84-200; Seabrook 1 Investigation; New Hampshire Public Advocate; November 15, 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. Massachusetts Division of Insurance; Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November, 1984.

Profit margin calculations, including methodology and implementation.

40. MDPU 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12, 1984.

Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. Maine PUC 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11, 1984.

Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. Maine PUC 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14, 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. MDPU 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14, 1985.

Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. Vermont PSB 4936; Millstone 3: Costs and In-Service Date; Vermont Department of Public Service; January 21, 1985.

Construction schedule and cost of completing Millstone Unit 3.

45. MDPU 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25, 1985, and October 18, 1985.

Institutional and technological advantages of Qualifying Facilities (QF's). Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. MDPU 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12, 1985.

Calculation of return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. Massachusetts Division of Insurance; Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General; November, 1985.

Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

Allowing

48. Pennsylvania PUC R-850152; Philadelphia Electric Rate Case; Utility Users Committee and Univeristy of Pennsylvania; January 14, 1986.

Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

APPENDIX B:

SIMPLIFIED RATEMAKING MODEL

Table B-1: Total Revenue Required, No Decommissioning Fund ($1000)

Income Tax Multiplier	1.97	Inflation, Expenses	6.0%
Equity as % of Capital	50.0%	Inflation, Rate Base	3.0%
Debt as % of Capital	50.0%	Equity Rate	15.0%
Tax Credits (as % of rate base)	4.3%	Debt Rate	12.0%

Year	Expenses	Rate Base	Equity Return	Debt Return	Taxes	Total Revenue Required
1986	$150,000	$1,000,000	$75,000	$60,000	$30,250	$315,250
1987	$159,000	$1,030,000	$77,250	$61,800	$31,158	$329,208
1988	$168,540	$1,060,900	$79,568	$63,654	$32,092	$343,854
1989	$178,652	$1,092,727	$81,955	$65,564	$33,055	$359,226
1990	$189,372	$1,125,509	$84,413	$67,531	$34,047	$375,362
1991	$200,734	$1,159,274	$86,946	$69,556	$35,068	$392,304
1992	$212,778	$1,194,052	$89,554	$71,643	$36,120	$410,095
1993	$225,545	$1,229,874	$92,241	$73,792	$37,204	$428,781
1994	$239,077	$1,266,770	$95,008	$76,006	$38,320	$448,411
1995	$253,422	$1,304,773	$97,858	$78,286	$39,469	$469,036
1996	$268,627	$1,343,916	$100,794	$80,635	$40,653	$490,709
1997	$284,745	$1,384,234	$103,818	$83,054	$41,873	$513,489
1998	$301,829	$1,425,761	$106,932	$85,546	$43,129	$537,436
1999	$319,939	$1,468,534	$110,140	$88,112	$44,423	$562,614
2000	$339,136	$1,512,590	$113,444	$90,755	$45,756	$589,091
2001	$359,484	$1,557,967	$116,848	$93,478	$47,129	$616,939
2002	$381,053	$1,604,706	$120,353	$96,282	$48,542	$646,230
2003	$403,916	$1,652,848	$123,964	$99,171	$49,999	$677,049
2004	$428,151	$1,702,433	$127,682	$102,146	$51,499	$709,479
2005	$453,840	$1,753,506	$131,513	$105,210	$53,044	$743,607
2006	$481,070	$1,806,111	$135,458	$108,367	$54,635	$779,530
2007	$509,935	$1,860,295	$139,522	$111,618	$56,274	$817,348
2008	$540,531	$1,916,103	$143,708	$114,966	$57,962	$857,167
2009	$572,962	$1,973,587	$149,019	$118,415	$59,701	$899,098
2010	$607,340	$2,032,794	$152,460	$121,968	$61,492	$943,259
2011	$643,781	$2,093,778	$157,033	$125,627	$63,337	$989,777
2012	$682,407	$2,156,591	$161,744	$129,395	$65,237	$1,038,784
2013	$723,352	$2,221,289	$166,597	$133,277	$67,194	$1,090,420
2014	$766,753	$2,287,928	$171,595	$137,276	$69,210	$1,144,835
2015	$812,758	$2,356,566	$176,742	$141,394	$71,286	$1,202,181
2016	$861,524	$2,427,262	$182,045	$145,636	$73,425	$1,262,629
2017	$913,215	$2,500,080	$187,506	$150,006	$75,627	$1,326,353
2018	$968,008	$2,575,083	$193,131	$154,505	$77,896	$1,393,540
2019	$1,026,088	$2,652,335	$198,925	$159,140	$80,233	$1,464,387
2020	$1,087,654	$2,731,905	$204,893	$163,914	$82,640	$1,539,101
2021	$1,152,913	$2,813,862	$211,040	$168,832	$85,119	$1,617,904
2022	$1,222,088	$2,898,278	$217,371	$173,897	$87,673	$1,701,028
2023	$1,295,413	$2,985,227	$223,992	$179,114	$90,303	$1,758,727

Table B-2: Total Revenue Required, External Decommissioning Fund, EPE Portfolio Assumptions ($1000)

Income Tax Multiplier	1.97	Inflation, Expenses	6.0%	Interest on Fund	9.91%
Equity as % of Capital	50.0%	Inflation, Rate Base	3.0%		
Debt as % of Capital	50.0%	Equity Rate	15.0%		
Tax Credits (as % of Rate Base)	4.3%	Debt Rate	12.0%		

Year	Decommissioning Charge	Decommissioning Expenses	Expenses	Rate Base	Equity Return	Debt Return	Taxes	Total Revenue Required	External Decommissioning Fund Balance
1986	$493	$0	$150,000	$1,000,000	$75,000	$60,000	$30,250	$315,743	$493
1987	$493	$0	$159,000	$1,030,000	$77,250	$61,800	$31,158	$329,701	$1,035
1988	$493	$0	$168,540	$1,060,900	$79,568	$63,654	$32,092	$344,347	$1,630
1989	$493	$0	$178,652	$1,092,727	$81,955	$65,564	$33,055	$359,719	$2,285
1990	$493	$0	$189,372	$1,125,509	$84,413	$67,531	$34,047	$375,855	$3,004
1991	$493	$0	$200,734	$1,159,274	$86,946	$69,556	$35,068	$392,797	$3,795
1992	$493	$0	$212,778	$1,194,052	$89,554	$71,643	$36,120	$410,588	$4,664
1993	$493	$0	$225,545	$1,229,874	$92,241	$73,792	$37,204	$429,274	$5,619
1994	$493	$0	$239,077	$1,266,770	$95,008	$76,006	$38,320	$448,904	$6,663
1995	$493	$0	$253,422	$1,304,773	$97,858	$78,286	$39,469	$469,529	$7,823
1996	$493	$0	$268,627	$1,343,916	$100,794	$80,635	$40,653	$491,202	$9,093
1997	$493	$0	$284,745	$1,384,234	$103,818	$83,054	$41,873	$513,382	$10,486
1998	$493	$0	$301,829	$1,425,761	$106,932	$85,546	$43,129	$537,929	$12,018
1999	$493	$0	$319,939	$1,468,534	$110,140	$88,112	$44,423	$563,107	$13,702
2000	$493	$0	$339,136	$1,512,590	$113,444	$90,755	$45,756	$589,584	$15,553
2001	$493	$0	$359,484	$1,557,967	$116,848	$93,478	$47,129	$617,431	$17,587
2002	$493	$0	$381,053	$1,604,706	$120,353	$96,282	$48,542	$646,723	$19,823
2003	$493	$0	$403,916	$1,652,848	$123,964	$99,171	$49,999	$677,542	$22,280
2004	$493	$0	$428,151	$1,702,433	$127,682	$102,146	$51,499	$709,971	$24,981
2005	$493	$0	$453,840	$1,753,506	$131,513	$105,210	$53,044	$744,100	$27,950
2006	$493	$0	$481,070	$1,806,111	$135,458	$108,367	$54,635	$780,027	$31,213
2007	$493	$0	$509,935	$1,860,295	$139,522	$111,618	$56,274	$817,941	$34,799
2008	$493	$0	$540,531	$1,916,103	$143,708	$114,966	$57,962	$857,560	$38,740
2009	$493	$0	$572,962	$1,973,587	$148,019	$118,415	$59,701	$899,591	$43,072
2010	$493	$0	$607,340	$2,032,794	$152,460	$121,968	$61,492	$943,752	$47,834
2011	$493	$0	$643,781	$2,093,778	$157,033	$125,627	$63,337	$990,279	$53,067
2012	$493	$0	$682,407	$2,156,591	$161,744	$129,395	$65,237	$1,039,277	$58,819
2013	$493	$0	$723,352	$2,221,289	$166,597	$133,277	$67,194	$1,090,913	$65,141
2014	$493	$0	$766,753	$2,287,928	$171,595	$137,276	$69,210	$1,145,326	$72,089
2015	$493	$0	$812,758	$2,356,566	$176,742	$141,394	$71,286	$1,202,674	$79,728
2016	$493	$0	$861,524	$2,427,262	$182,045	$145,636	$73,425	$1,263,122	$88,122
2017	$493	$0	$913,215	$2,500,080	$187,506	$150,005	$75,627	$1,326,846	$97,348
2018	$493	$1,338	$968,008	$2,575,083	$193,131	$154,505	$77,896	$1,394,033	$106,149
2019	$493	$3,992	$1,026,088	$2,652,335	$198,925	$159,140	$80,233	$1,464,280	$113,168
2020	$493	$29,199	$1,087,654	$2,731,905	$204,893	$163,914	$82,640	$1,539,594	$95,577
2021	$0	$52,069	$1,152,913	$2,813,862	$211,040	$168,832	$85,119	$1,617,904	$53,099
2022	$0	$43,540	$1,222,088	$2,898,278	$217,371	$173,897	$87,673	$1,701,028	$14,811
2023	$0	$16,087	$1,295,413	$2,985,227	$223,692	$179,114	$90,503	$1,788,722	$192

Notes: Decommissioning Charges and Expenses from WJJ-1.

Table B-3: Total Revenue Required, Internal Decommissioning Fund

Income Tax Multiplier	1.97	Inflation, Expenses	6.0%
Equity as % of Capital	50.0%	Inflation, Rate Base	3.0%
Debt as % of Capital	50.0%	Equity Rate	15.0%
Tax Credits (as % of Rate Base)	4.3%	Debt Rate	12.0%

Year	Decom-missioning Charge	Decom-missioning Expenses	Internal Decom-missioning Fund Balance	Expenses	Rate Base	Net Rate Base	Equity Return	Debt Return	Taxes	Total Revenue Required
1986	$330	$0	$330	$150,000	$1,000,000	$1,000,000	$75,000	$60,000	$30,570	$315,900
1987	$330	$0	$660	$159,000	$1,030,000	$1,029,670	$77,225	$61,780	$31,454	$329,795
1988	$330	$0	$990	$168,540	$1,060,900	$1,060,240	$79,518	$63,614	$32,364	$344,367
1989	$670	$0	$1,660	$178,652	$1,092,727	$1,091,737	$81,880	$65,504	$33,633	$360,340
1990	$670	$0	$2,330	$189,372	$1,125,509	$1,123,849	$84,289	$67,431	$34,576	$376,337
1991	$670	$0	$3,000	$200,734	$1,159,274	$1,156,944	$86,771	$69,417	$35,548	$393,140
1992	$1,000	$0	$4,000	$212,778	$1,194,052	$1,191,052	$89,329	$71,463	$36,872	$411,442
1993	$1,000	$0	$5,000	$225,545	$1,229,874	$1,225,874	$91,941	$73,552	$37,883	$429,920
1994	$1,000	$0	$6,000	$239,077	$1,266,770	$1,261,770	$94,633	$75,706	$38,926	$449,342
1995	$1,335	$0	$7,335	$253,422	$1,304,773	$1,298,773	$97,408	$77,926	$40,328	$470,419
1996	$1,335	$0	$8,670	$268,627	$1,343,916	$1,336,581	$100,244	$80,195	$41,415	$491,315
1997	$1,335	$0	$10,005	$284,745	$1,384,234	$1,375,564	$103,167	$82,534	$42,537	$514,318
1998	$1,668	$0	$11,673	$301,829	$1,425,761	$1,415,756	$106,182	$84,945	$44,019	$533,643
1999	$1,668	$0	$13,340	$319,939	$1,468,534	$1,456,861	$109,265	$87,412	$45,191	$563,474
2000	$1,668	$0	$15,008	$339,136	$1,512,590	$1,499,250	$112,444	$89,955	$46,403	$599,605
2001	$2,000	$0	$17,008	$359,484	$1,557,968	$1,542,960	$115,722	$92,578	$47,977	$617,760
2002	$2,000	$0	$19,008	$381,053	$1,604,706	$1,587,699	$119,077	$95,262	$49,245	$646,537
2003	$2,000	$0	$21,008	$403,916	$1,652,848	$1,633,840	$122,538	$98,030	$50,556	$677,040
2004	$2,335	$0	$23,343	$428,151	$1,702,433	$1,681,425	$126,107	$100,885	$52,235	$709,714
2005	$2,335	$0	$25,678	$453,840	$1,753,506	$1,730,163	$129,762	$103,810	$53,610	$743,357
2006	$2,335	$0	$28,013	$481,070	$1,806,111	$1,780,434	$133,533	$106,826	$55,032	$778,796
2007	$2,668	$0	$30,680	$509,935	$1,860,295	$1,832,282	$137,421	$109,937	$56,823	$815,784
2008	$2,668	$0	$33,348	$540,531	$1,916,103	$1,885,423	$141,407	$113,125	$58,318	$855,049
2009	$2,668	$0	$36,015	$572,962	$1,973,587	$1,940,239	$145,519	$116,414	$59,862	$897,425
2010	$3,003	$0	$39,018	$607,340	$2,032,794	$1,996,779	$149,758	$119,807	$61,784	$941,692
2011	$3,003	$0	$42,020	$643,781	$2,093,778	$2,054,760	$154,107	$123,286	$63,411	$987,595
2012	$3,003	$0	$45,023	$682,407	$2,156,591	$2,114,571	$158,593	$126,874	$65,092	$1,035,963
2013	$3,332	$0	$48,355	$723,352	$2,221,289	$2,175,266	$163,220	$130,516	$67,151	$1,087,531
2014	$3,332	$0	$51,688	$766,753	$2,287,928	$2,239,572	$167,968	$134,374	$68,924	$1,141,352
2015	$3,332	$0	$55,020	$812,758	$2,356,566	$2,304,878	$172,866	$138,293	$70,758	$1,196,307
2016	$3,670	$0	$58,690	$861,524	$2,427,262	$2,372,242	$177,918	$142,335	$72,982	$1,258,422
2017	$3,670	$0	$62,360	$913,215	$2,500,080	$2,441,390	$183,104	$146,483	$74,918	$1,321,390
2018	$3,670	$679	$65,351	$968,008	$2,575,083	$2,512,722	$188,454	$150,763	$76,919	$1,387,915
2019	$4,096	$2,026	$67,421	$1,026,088	$2,652,335	$2,586,984	$194,024	$155,219	$79,452	$1,456,680
2020	$4,099	$14,822	$56,698	$1,087,654	$2,731,905	$2,664,484	$199,836	$159,869	$81,711	$1,533,169
2021	$0	$26,431	$30,268	$1,152,913	$2,813,862	$2,757,164	$206,787	$165,430	$80,395	$1,606,125
2022	$0	$22,102	$8,166	$1,222,088	$2,898,278	$2,868,011	$215,101	$172,081	$85,471	$1,694,740
2023	$0	$8,166	($.00)	$1,295,413	$2,985,227	$2,977,061	$223,280	$178,624	$89,709	$1,787,025

Notes: Decommissioning Charges and Expenses from EPE exhibit WJJ-3, divided by Income Tax Multiplier.

Table B-4: Summary of Cases

	REVENUE REQUIREMENTS			REVENUE DIFFERENCES	
Year	No Fund (Table B-1)	External Fund (Table B-2)	Internal Fund (Table B-3)	External - No Fund	Internal - No Fund
1986	$315,250	$315,743	$315,900	$493	$650
1987	$329,208	$329,701	$329,789	$493	$581
1988	$343,854	$344,347	$344,367	$493	$513
1989	$359,226	$359,719	$360,340	$493	$1,114
1990	$375,362	$375,855	$376,337	$493	$975
1991	$392,304	$392,797	$393,140	$493	$836
1992	$410,095	$410,588	$411,442	$493	$1,347
1993	$428,781	$429,274	$429,920	$493	$1,139
1994	$448,411	$448,904	$449,342	$493	$931
1995	$469,036	$469,529	$470,419	$493	$1,384
1996	$490,709	$491,202	$491,815	$493	$1,106
1997	$513,489	$513,982	$514,318	$493	$829
1998	$537,436	$537,929	$538,643	$493	$1,206
1999	$562,614	$563,107	$563,474	$493	$860
2000	$589,091	$589,584	$589,605	$493	$514
2001	$616,938	$617,431	$617,760	$493	$822
2002	$646,230	$646,723	$646,637	$493	$407
2003	$677,049	$677,542	$677,040	$493	($9)
2004	$709,478	$709,971	$709,714	$493	$236
2005	$743,607	$744,100	$743,357	$493	($249)
2006	$779,530	$780,023	$778,796	$493	($735)
2007	$817,348	$817,841	$816,784	$493	($565)
2008	$857,167	$857,660	$856,048	$493	($1,119)
2009	$899,099	$899,591	$897,425	$493	($1,673)
2010	$943,259	$943,752	$941,692	$493	($1,567)
2011	$989,777	$990,270	$987,586	$493	($2,191)
2012	$1,038,784	$1,039,277	$1,035,969	$493	($2,815)
2013	$1,090,420	$1,090,913	$1,087,631	$493	($2,788)
2014	$1,144,833	$1,145,326	$1,141,352	$493	($3,481)
2015	$1,202,181	$1,202,674	$1,198,007	$493	($4,173)
2016	$1,262,629	$1,263,122	$1,258,429	$493	($4,200)
2017	$1,326,353	$1,326,846	$1,321,390	$493	($4,963)
2018	$1,393,540	$1,394,033	$1,387,815	$493	($5,725)
2019	$1,464,387	$1,464,880	$1,458,880	$493	($5,507)
2020	$1,539,101	$1,539,594	$1,533,169	$493	($5,932)
2021	$1,617,904	$1,617,904	$1,606,125	$0	($11,779)
2022	$1,701,028	$1,701,028	$1,694,740	$0	($6,288)
2023	$1,788,722	$1,788,722	$1,787,025	$0	($1,696)

APPENDIX C:

EXHIBITS FROM

W. J. JOHNSON TESTIMONY

Exhibit WJJ-1

EL PASO ELECTRIC COMPANY
REVENUE REQUIREMENTS FOR DECOMISSIONING PALO VERDE UNIT NO. 1
9% EXTERNAL FUND (4.86% AFTER TAX)

Line No.	(1) Year	(2) Annuity	(3) Interest	(4) Decomissioning Expense	(5) Fund Balance
1	1986	1,573	0	0	1,573
2	1987	1,573	76	0	3,222
3	1988	1,573	157	0	4,952
4	1989	1,573	241	0	6,766
5	1990	1,573	329	0	8,568
6	1991	1,573	421	0	10,662
7	1992	1,573	518	0	12,753
8	1993	1,573	620	0	14,946
9	1994	1,573	727	0	17,246
10	1995	1,573	838	0	19,657
11	1996	1,573	956	0	22,186
12	1997	1,573	1,079	0	24,838
13	1998	1,573	1,207	0	27,618
14	1999	1,573	1,343	0	30,534
15	2000	1,573	1,484	0	33,591
16	2001	1,573	1,633	0	36,797
17	2002	1,573	1,789	0	40,159
18	2003	1,573	1,952	0	43,684
19	2004	1,573	2,124	0	47,381
20	2005	1,573	2,303	0	51,257
21	2006	1,573	2,492	0	55,322
22	2007	1,573	2,689	0	59,584
23	2008	1,573	2,897	0	64,054
24	2009	1,573	3,114	0	68,741
25	2010	1,573	3,342	0	73,656
26	2011	1,573	3,581	0	78,809
27	2012	1,573	3,831	0	84,213
28	2013	1,573	4,094	0	89,880
29	2014	1,573	4,369	0	95,823
30	2015	1,573	4,658	0	102,054
31	2016	1,573	4,961	0	108,588
32	2017	1,573	5,279	0	115,440
33	2018	1,573	5,612	(1,338)	121,287
34	2019	1,573	5,896	(3,992)	124,764
35	2020	1,573	6,065	(29,199)	103,203
36	2021	0	5,017	(52,069)	56,151
37	2022	0	2,730	(43,540)	15,341
38	2023	0	746	(16,087)	0
39	Total	55,055	91,170	(146,225)	

Exhibit WJJ-2

EL PASO ELECTRIC COMPANY
REVENUE REQUIREMENTS FOR DECOMISSIONING PALO VERDE UNIT NO. 1
9% INTERNAL FUND

Line No.	(1) Year	(2) Annuity	(3) Interest	(4) Decomissioning Expense	(5) Fund Balance	(6) Revenue Required
1	1986	612	0	0	612	612
2	1987	612	55	0	1,279	605
3	1988	612	115	0	2,006	597
4	1989	612	181	0	2,799	588
5	1990	612	252	0	3,663	579
6	1991	612	330	0	4,604	569
7	1992	612	414	0	5,631	557
8	1993	612	507	0	6,749	545
9	1994	612	607	0	7,969	532
10	1995	612	717	0	9,298	517
11	1996	612	837	0	10,747	502
12	1997	612	967	0	12,326	484
13	1998	612	1,109	0	14,047	466
14	1999	612	1,264	0	15,924	445
15	2000	612	1,433	0	17,969	423
16	2001	612	1,617	0	20,198	399
17	2002	612	1,818	0	22,628	372
18	2003	612	2,037	0	25,276	343
19	2004	612	2,275	0	28,163	312
20	2005	612	2,535	0	31,310	278
21	2006	612	2,818	0	34,740	240
22	2007	612	3,127	0	38,478	200
23	2008	612	3,463	0	42,553	155
24	2009	612	3,830	0	46,995	107
25	2010	612	4,230	0	51,837	54
26	2011	612	4,665	0	57,114	(3)
27	2012	612	5,140	0	62,866	(66)
28	2013	612	5,658	0	69,136	(134)
29	2014	612	6,222	0	75,971	(209)
30	2015	612	6,837	0	83,420	(290)
31	2016	612	7,508	0	91,540	(378)
32	2017	612	8,239	0	100,390	(474)
33	2018	612	9,035	(1,338)	108,700	(579)
34	2019	605	9,783	(3,992)	115,095	(685)
35	2020	584	10,359	(29,199)	96,339	(782)
36	2021	0	8,716	(52,069)	53,486	(1,149)
37	2022	0	4,814	(43,540)	14,759	(635)
38	2023	0	1,328	(16,087)	1	(175)
39	Total	21,385	124,841	(146,225)		4,923

Exhibit WJJ-3

EL PASO ELECTRIC COMPANY
REVENUE REQUIREMENTS FOR DECOMISSIONING PALO VERDE UNIT NO. 1
THREE YEAR INC SL METHOD

Line No.	(1) Year	(2) Annuity	(3) Interest	(4) Decomissioning Expense	(5) Fund Balance	(6) Revenue Required
1	1986	650	0	0	650	650
2	1987	650	0	0	1,300	584
3	1988	650	0	0	1,950	518
4	1989	1,320	0	0	3,270	1,121
5	1990	1,320	0	0	4,590	987
6	1991	1,320	0	0	5,910	852
7	1992	1,970	0	0	7,880	1,368
8	1993	1,970	0	0	9,850	1,167
9	1994	1,970	0	0	11,820	967
10	1995	2,630	0	0	14,450	1,426
11	1996	2,630	0	0	17,080	1,158
12	1997	2,630	0	0	19,710	890
13	1998	3,285	0	0	22,995	1,277
14	1999	3,285	0	0	26,280	943
15	2000	3,285	0	0	29,565	608
16	2001	3,940	0	0	33,505	928
17	2002	3,940	0	0	37,445	527
18	2003	3,940	0	0	41,385	126
19	2004	4,600	0	0	45,985	384
20	2005	4,600	0	0	50,585	(84)
21	2006	4,600	0	0	55,185	(553)
22	2007	5,255	0	0	60,440	(367)
23	2008	5,255	0	0	65,695	(902)
24	2009	5,255	0	0	70,950	(1,437)
25	2010	5,915	0	0	76,865	(1,313)
26	2011	5,915	0	0	82,780	(1,915)
27	2012	5,915	0	0	88,695	(2,513)
28	2013	6,565	0	0	95,260	(2,470)
29	2014	6,565	0	0	101,825	(3,139)
30	2015	6,565	0	0	108,390	(3,808)
31	2016	7,230	0	0	115,620	(3,811)
32	2017	7,230	0	0	122,850	(4,548)
33	2018	7,230	0	(1,338)	128,742	(5,284)
34	2019	8,070	0	(3,992)	132,820	(5,045)
35	2020	8,075	0	(29,199)	111,696	(5,455)
36	2021	0	0	(52,069)	59,627	(11,378)
37	2022	0	0	(43,540)	16,087	(6,074)
38	2023	0	0	(16,087)	0	(1,639)
39	Total	146,225	0	(146,225)		(45,250)

EL PASO ELECTRIC COMPANY
DECOMMISSIONING EXPENSE
SUMMARY

Exhibit W.

Line No.	Year	(1) Decommissioning In Rates: Modified St. Line	(2) Decommissioning In Rates: Tax Deductible 9%	(3) Decommissioning In Rates: Internal 9% Annuity	(4) Revenue Net Reserve Requirement: Modified St. Line	(5) Revenue Net Reserve Requirement: Tax Deductible 9%	(6) Revenue Net Reserve Requirement: Internal 9% Annuity	(7) Decommissioning Reserve: Modified St. Line	(8) Decommissioning Reserve: Tax Deductible 9%	(9) Decommissioning Reserve: Internal 9% Annuity	(10) Decommission: Funds Needed
1	1986	650	1,573	612	650	1,573	612	330	1,573	311	9,546
2	1987	650	1,573	677	584	1,573	605	660	3,222	650	10,119
3	1988	650	1,573	727	518	1,573	597	990	4,952	1,019	10,726
4	1989	1,320	1,573	793	1,121	1,573	588	1,661	6,766	1,471	11,370
5	1990	1,320	1,573	864	987	1,573	579	2,331	8,668	1,860	12,052
6	1991	1,320	1,573	942	852	1,573	569	3,001	10,662	2,338	12,775
7	1992	1,970	1,573	1,026	1,368	1,573	557	4,001	12,753	2,859	13,542
8	1993	1,970	1,573	1,119	1,167	1,573	545	5,002	14,946	3,427	14,354
9	1994	1,970	1,573	1,219	967	1,573	532	6,002	17,246	4,047	15,215
10	1995	2,630	1,573	1,329	1,426	1,573	517	7,338	19,657	4,722	16,128
11	1996	2,630	1,573	1,449	1,158	1,573	502	8,673	22,186	5,457	17,096
12	1997	2,630	1,573	1,579	890	1,573	484	10,009	24,838	6,259	18,122
13	1998	3,285	1,573	1,721	1,277	1,573	466	11,677	27,618	7,133	19,209
14	1999	3,285	1,573	1,876	943	1,573	445	13,345	30,534	8,086	20,362
15	2000	3,285	1,573	2,045	608	1,573	423	15,013	33,591	9,125	21,583
16	2001	3,940	1,573	2,229	928	1,573	399	17,014	36,767	10,257	22,878
17	2002	3,940	1,573	2,430	527	1,573	372	19,015	40,159	11,490	24,251
18	2003	3,940	1,573	2,649	126	1,573	343	21,015	43,684	12,835	25,706
19	2004	4,600	1,573	2,887	384	1,573	312	23,351	47,181	14,301	27,248
20	2005	4,600	1,573	3,147	(84)	1,573	278	25,687	51,257	15,899	28,883
21	2006	4,600	1,573	3,430	(553)	1,573	240	28,023	55,322	17,641	30,616
22	2007	5,255	1,573	3,739	(367)	1,573	200	30,692	59,584	19,539	32,453
23	2008	5,255	1,573	4,075	(902)	1,573	155	33,360	64,054	21,609	34,400
24	2009	5,255	1,573	4,442	(1,437)	1,573	107	36,029	68,741	23,864	36,464
25	2010	5,915	1,573	4,842	(1,313)	1,573	54	39,032	73,656	26,323	38,652
26	2011	5,915	1,573	5,277	(1,915)	1,573	(3)	42,036	78,809	29,003	40,972
27	2012	5,915	1,573	5,752	(2,518)	1,573	(66)	45,040	84,213	31,924	43,430
28	2013	6,565	1,573	6,270	(2,470)	1,573	(134)	48,373	89,880	35,108	46,036
29	2014	6,565	1,573	6,834	(3,139)	1,573	(209)	51,707	95,823	38,578	48,798
30	2015	6,565	1,573	7,449	(3,808)	1,573	(290)	55,041	102,054	42,361	51,726
31	2016	7,230	1,573	8,120	(3,811)	1,573	(378)	58,712	108,588	46,484	54,829
32	2017	7,230	1,573	8,851	(4,548)	1,573	(474)	62,384	115,440	50,979	58,119
33	2018	7,230	1,573	9,636	(5,284)	1,573	(579)	66,055	121,287	55,877	61,606
34	2019	8,070	1,573	10,388	(5,045)	1,573	(685)	69,473	124,764	60,473	64,582
35	2020	8,075	1,573	10,943	(5,455)	1,573	(782)	71,547	103,203	64,002	66,308
36		0	0	8,716	(11,378)	0	(1,149)	56,719	56,151	53,601	54,56[illegible]
37		0	0	4,814	(6,074)	0	(635)	30,279	11,341	29,604	29,81[illegible]
38		0	0	1,328	(1,639)	0	(175)	8,169	0	8,169	8,16[illegible]
39	Total	146,225	55,055	146,226	(45,260)	55,055	4,923				

APPENDIX D:

DESIGN, COSTS AND ACCEPTABILITY OF AN ELECTRIC UTILITY SELF-INSURANCE POOL FOR ASSURING THE ADEQUACY OF FUNDS FOR NUCLEAR POWER PLANT DECOMMISSIONING EXPENSE

ANALYSIS AND INFERENCE, INC. RESEARCH AND CONSULTING

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APPENDIX D:

NUREG/CR-2370

Design, Costs, and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense

Prepared by P. L. Chernick, W. B. Fairley, M. B. Meyer, L. C. Scharff

Analysis and Inference, Inc.

Prepared for
U.S. Nuclear Regulatory
Commission

APPENDIX E:

POWER PLANT PERFORMANCE STANDARDS: SOME INTRODUCTORY PRINCIPLES

Power Plant Performance Standards: Some Introductory Principles

By PAUL L. CHERNICK

This article describes some approaches to the determination of how well electric power generating plants perform, demonstrating their applications and citing their respective advantages. The techniques described may be used to determine whether a plant's efficiency is adequate and whether units with the lowest running costs are being sufficiently utilized.

Interest in assessing the prudence of electric utility fuel costs has increased over the last several years, as a result of rising fuel costs and large utility construction programs intended to displace expensive fuel sources, primarily with coal and nuclear fuel.[1] Several regulatory agencies have attempted to pass some of the costs (or benefits) of inadequate (or superior) performance on to the utilities, by modifying the amount or the timing of reimbursement for fuel costs, operation and maintenance expenses, rate base, or return on equity.

This article explores some approaches to determining how well power plants should perform, and discusses the advantages and applications of each. These techniques may be applied to determine both whether the efficiency (heat rate) of plants which burn large dollar amounts of fuel is adequate, and whether the units with the lowest running costs were available and utilized sufficiently.

Some Basic Approaches

In setting power plant performance standards, the fundamental objective is to develop *normative* or *prescriptive* goals, specifying how the plants *should* behave. This is a very different concept from *positive* or *descriptive* projections, which predict how the plants *will* behave. These two types of analyses have very different purposes and may yield very different results. For example, if a utility's plant breaks down in 1983, an accurate positive analysis might project a 1984 capacity factor of zero. Regulators may well determine that 1984 fuel costs should only reflect the costs which would have been incurred if the plant had been available. Thus, the normative standard may be different from both the actual performance and from the best estimate of future performance.

There are three basic types of alternative approaches which can be taken to establishing standards for power plant performance. First, each unit's performance standard can be determined by a *self-referent* standard, based on the unit's past performance. Self-referent standards may be set at various levels of stringency, such as:

- The unit will perform at least as well as its best past performance.
- The unit will perform at least as well as its average past performance.
- The unit will perform at least as well as its worst past performance.

Any of these standards may be calculated from any time period – e.g., last year, or the plant's entire life – and for a variety of intervals (monthly data, annual data).

These self-referent methods are easy to estimate and apply, but they do not usually produce fair and even-handed standards. Self-referent standards are inherently stricter for those units with good performance histories than for those with poor past performance. This is hardly a fitting reward for those utilities which have historically taken the greatest care in plant operation. In fact, it penalizes the best past performers and rewards the worst. There is generally no compelling reason for believing that the unit's history is representative of an appropriate level of performance (neither

[1]See *Innovative Regulatory Approaches to Power Plant Productivity and Cost Allocation Issues*, by L. Danielson, California Energy Commission, September, 1981, for a review of regulatory actions to that time.

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extraordinary nor inadequate), so self-referent standards are not likely to be useful in identifying efficient and cost-efficient operations.

In the second group of options, standards are based on *comparative* analyses, which aggregate the experience of other units. This approach would include such standards as:

- The unit will perform as well as the average comparable unit.
- The unit will perform as well as the average *competently run* unit.
- The unit will perform better than half (or any other percentage) of the comparable units.

The comparisons may simply average data from a set of units which share some common characteristics, or they may involve more complex statistical analyses, such as regression. Simple comparisons are generally performed on a set of very similar units, as it is difficult to justify direct comparisons between units which are known to vary in any relevant manner. The differences which are relevant are those which can be expected to affect performance: vintage, age, operating pressure, size, fuel type, and so on. The resulting data sets tend to be small, and the comparability of the units is always subject to some dispute. Various statistical techniques may mitigate these limitations. In multiple regressions, for example, several descriptive variables may be incorporated simultaneously, facilitating the merging of data from a greater variety of units. Statistical tests can also be useful in determining whether particular units belong in a comparison group.

Even though both self-referent and comparative analyses use actual operating data, they are not just descriptions of that data. Positive models describe the way things are (or have been), leading to such conclusions as "In their second year of operation, 800-megawatt pressurized water reactors have an average capacity factor of 55 per cent." This sort of statement is not a performance standard; it only becomes a standard when a prescription is added, such as "Therefore, this particular reactor should have a 55 per cent capacity factor in its second year." The way things are may be the basis for determining the way things should be, but this relationship is not automatic.

In the third group of approaches, standards are to be based on *absolute* measures of proper performances, such as:

- The unit will perform as was promised, or expected.
- The unit will perform as well as the utility has assumed for other purposes, such as rate design, setting small power producer rates, and capacity planning.
- The unit will perform well enough to justify its fixed costs.

None of these various absolute standards depends on actual performance data, either for the subject plant or for other plants. The first example suggests that, when the utility (and hence, the ratepayers) buys a generating unit, it should get what it (and they) expected. The second example suggests the standards applied in a plant performance standard review, where overoptimistic projections cause problems for the utility, should be the same as those used in proceedings where overoptimistic projections cause problems for ratepayers, such as capacity planning and rate design. The last example suggests that, regardless of what the utility expected, or predicted, or should have expected for the unit, the real issue is whether the unit is paying its own way.

Selecting a Standard Setting Approach

No one particular approach to standard setting is preferable in all applications. The various kinds of standards are appropriate for different situations. As noted above, self-referent standards raise major equity issues. If applied on a rolling basis – e.g., if the standard in any year is determined by performance in the preceding three years – serious and perverse incentive problems may be created. Self-referent standards are also inherently inapplicable to new units. There are special circumstances in which self-referent standards are useful, particularly when no other basis for standard setting exists. Examples of these situations would include the small nuclear reactors completed in the early 1960s, the few geothermal plants currently operating, and such new technologies as wood burning units and fluidized bed plants. These are the exceptions, rather than the rule.

Comparative standards are appealing wherever a reasonable comparison group exists. They are not applicable for experimental units and other unique designs.[2] Comparative analyses establish business-as-usual standards, general industry performance levels as the basis for determining whether a utility may deserve a bonus or penalty.

Absolute standard setting approaches rely on other concepts of fairness, which may be applicable even where business is far from usual. For example, using preoperational expectations to set performance standards is intrinsically appealing: If a utility sets out to build a plant which will operate in a particular manner, it should be able to explain why the actual plant is significantly different than the expected one. Similarly, utilities should be encouraged to present consistent projections in different proceedings, whether they are requesting permission to build the plants of their choice; estimating marginal generation costs to determine whether declining blocks are justified, whether conservation programs are cost effective, and whether higher rates for small power producers are necessary; or determining the level of fuel cost recovery.

The application of the prior expectations approach is limited to those performance factors and units for which reasonably serious expectations and representations are available. For many fossil units constructed

[2]The concept of uniqueness must be applied carefully. In one sense, no steam power plant is unique, since all such plants are alike in having a boiler, a turbine, and a heat sink. In another sense, every unit is unique, except for those few sister units which are *exact* carbon copies. Generally speaking, if a group of similar units can be defined, a meaningful comparative analysis can be conducted, and statistical tests can determine whether differences between plants are important.

prior to the establishment of regulatory review, no reliability measures were ever projected. For other technologies, early performance expectations were widely held, based on virtually no data, and seriously incorrect; this certainly was true of projections for nuclear capacity factors made in the 1960s and early 1970s. In such cases, it seems unfair to hold an individual utility responsible for a universal, and perhaps understandable, error.

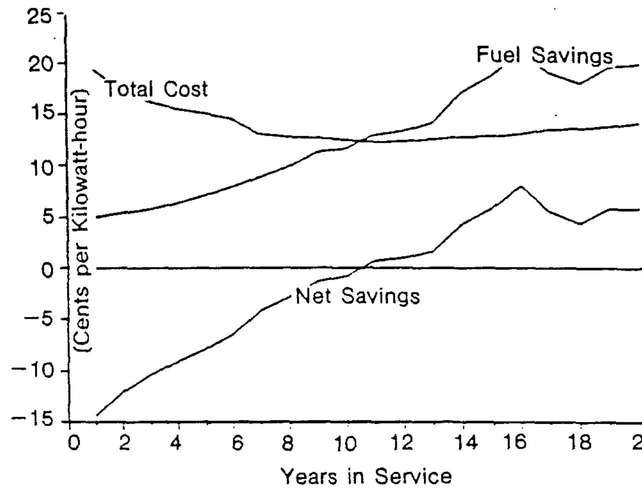
As an alternative to the projection standard, the cost-effectiveness standard may be particularly appealing: This standard asks only that the ratepayers be better off with the plant than without it, but this may be all that can be expected from new (and especially from exotic) generating units. This standard can be derived for all units, regardless of the existence of a comparison group, of prior data on the unit's own performance, or of preoperational projections.

A break-even standard may also be particularly appropriate in the case of the many relatively expensive nuclear plants[3] nearing completion. Those plants are being built with the knowledge that they will be far more expensive per kilowatt than other capacity sources, but with the expectation that they will pay off the additional capital costs through long hours of output at very low fuel cost. In many cases, it has long been clear that the plant would not be necessary in the near future for reliability purposes, yet construction was continued to realize the anticipated fuel savings. Since these plants are being built to save money, it seems reasonable to expect them to do so, or at least to investigate the reasons for their failure to break even, if that occurs.

The break-even standard would also help to solve a serious timing problem. Traditional rate-making treatment for expensive new base-load plants tends to impose a disproportionately large share of the costs on customers in the first few years of a generating plant's life, even though (under current conditions) most of the benefits are expected much later, often in the second half of the unit's life. Costs tend to fall over the first decade or so, due to depreciation of the rate base contribution. The benefits of major base-load plants are generally relatively small in the early years, while the price of the alternative fuels is low and the need for the added capacity does not exist. This pattern of costs and benefits is illustrated in the accompanying figure.[4]

As a result of this pattern of cost and benefits, customers in the early years (frequently a decade or more) wind up worse off than they would have been if the plant had never been built. This may be true even if the plant is justified by its later savings, to a substantially different mix of customers. Unfortunately, regulators must decide whether to allow full recovery for the cost of the plant before much of its benefits are experienced. At best, this situation amounts to a sizeable tax on today's customers to provide lower-cost power to tomorrow's customers. At worst, it may penalize utilities for units that will eventually pay off, and fail to recognize that other units never do.

New Nuclear Plants — Typical Cost Benefit Pattern



If the ratepayer benefits of the plant are constrained to be at least as large as the costs, the large ratepayer losses in the early years do not occur.[5] As a result, there is no subsidy (or less subsidy) by the ratepayers of the 1980s to the ratepayers of the next century. The people who receive the major benefits of the plant (avoiding the large costs of escalating fuel prices) also pay the major proportion of the costs.

A final advantage of break-even standards is that they would tend to encourage accurate cost forecasting and evenhanded planning on the part of utilities engaged in major construction projects. Traditionally, utilities have had very asymmetrical incentives regarding decisions to complete or cancel construction projects. Completed plants, whether economical, or needed, are generally placed in rate base more or less when they enter service.[6] Canceled plants are generally considered to be at least partially imprudent (or at least partially the responsibility of the stockholders), and their costs are rarely recovered in full from the ratepayers. Therefore, a utility which can actually complete and operate a new plant is largely home free, even if the net cost of the project is greater than the cost of cancellation. The result is that utilities frequently continue with construction projects long after an impartial analysis would indicate that they should be abandoned.

With a break-even cost recovery standard, this asymmetry is eliminated. Cost recovery will be far from automatic in any case, and (even if the plant is completed) will not rely on projections of future benefits. A completed plant which costs a billion dollars more than it is worth would pose the same problems for the utility as a plant which is canceled after a billion dollars have been spent on it. Therefore, the bias towards completion should be largely neutralized, and decisions regarding cancellation, deferral, or completion should be made on the basis of total future cost

[3]This reasoning also applies to some coal-fired units.

[4]The data are from Northeast Utilities, for Millstone 3, and are illustrative of the general problem.

[5]Alternatively, the nonfuel costs passed on to ratepayers may be constrained to be less than or equal to the savings received.

[6]More recently, some units have been phased into rate base over the period of a few years, resulting in limited costs being borne by the shareholders.

and benefits, without regard to whether customers or shareholders are likely to bear the costs.

In determining the kind and level of standard which is appropriate in a particular situation, it is important to consider the intended use of a performance standard. If the standards only set the level of a prospective fuel clause, or create an obligation for the utility to explain and justify any deviations from expected performance, they may be set in a relatively demanding fashion. Indeed, this would be true for any standards which basically flag performance requiring some scrutiny or explanation.[7] While a higher standard might be appropriate for this screening purpose, a lower one might be justified if there were automatic financial consequences when the utility failed to meet the standard.

Good Standards Require Thoughtful Design

Once a general approach to standard setting is chosen, several additional methodological issues will remain. I will only touch on a few of them here.

One problem in setting comparative standards for capacity factors and similar reliability measures is the selection of a consistent definition of plant capacity in the reference group. Some care must be taken to ensure that the capacity factors for other units in the comparison group[8] are all computed on the basis of the same measure of capacity, whether that is *design net,* or *dependable gross,* or some other comparable measure. If a comparative standard is to be based on a regression analysis, some of the variables which ideally ought to be examined include unit size, unit age, cooling system, design (e.g., once-through versus drum-type boilers), fuel type and quality (especially for coal-fired plants), pollution controls, maintenance schedules,[9] manufacturer of boiler and turbine, and regulatory environment.

The regulatory variable would include the reductions in nuclear capacity factors following the accident at Three Mile Island, and possibly future reductions in coal-plant reliability and efficiency due to acid rain legislation. My analyses of nuclear capacity factors indicate that the TMI effect is as important as age or size in determining performance, and that nuclear utilities would be unfairly penalized if their units were expected to perform as well in the early 1980s as they did in the mid-1970s.

For several of these variables, especially the age and size effects, the mathematical form which best approximates the effect on performance is of interest, and can be studied in considerable detail. The generally comparable data set may be improved for the specific purpose of determining average *prudent* performance by deleting the few specific unit-years which can be identified as reflecting acknowledged imprudent behavior on the part of the operators.[10]

A comparative standard can be applied in at least two ways: on an annual basis and on a cumulative basis. The annual standard simply takes the group projection for the size, current age, and other characteristics of the unit. In other words, it requires that: A unit of these characteristics shall perform this year at the average level of similar units. The cumulative approach derives the current year's standard which will bring the plant's cumulative performance to the group prediction.[11] Thus, the cumulative standard is indifferent to this year's performance, except to specify that: A unit of these characteristics shall *through this year* perform at the average level of similar units. The period used in the cumulative calculation may be the entire life of the plant, the mature portion of its life – e.g., from the fifth year of operation – or perhaps some other interval, such as the last five years.

For a unit which has performed well in the past, the cumulative standard is more lenient than the current standard; for a unit which has performed poorly, the cumulative standard is more stringent. In general, I believe that the cumulative standard is more equitable. A unit which performed exceedingly well in the past seems entitled to an off year or two, while one which has performed in an unsatisfactory manner has some catching up to do. On a more causal basis, the cumulative standard may be justified by the observation that many operating problems require some time out of service for their correction. A unit which has performed especially well may have deferred some maintenance or upgrading to achieve high reliability in the past, and may reasonably require more downtime now than a unit which has already been out of service for major modifications and maintenance.

If a cumulative performance standard is employed it may not be physically possible for particular units with poor performance histories to catch up in the first year of the standards,[12] while exceptional units might be guaranteed to exceed the standard. For the underachieving units, it may be necessary to set the targets at some lower, feasible level. Examples (for capacity factor) might be 100 per cent, or the highest annual capacity factor in the comparative data set, or some more likely value, such as 80 per cent. The lower the annual target, the longer a time is required to catch up to the average. Similar considerations are involved in setting standards for very successful units.

It is to be expected that many plants will fail the break-even standard for several of their early years, even if they eventually are quite valuable. So long as this is the case, I would recommend that the utility be allowed to accrue interest on the difference between its actual power supply costs and the fuel charges allowed under the break-even target. If the plant eventually pays off, the actual costs will be less than those under the (gradually decreasing) break-even standard, and the utility can collect its deferred fuel costs. In the ordinary case, in which the plant is economically justified, the deferred costs would gradually be recov-

[7]Or conversely, performance eligible for some reward.

[8]In general, the utility's own units should not be in the comparison group.

[9]This is particularly important for nuclear refuelings, and accounts for much of the otherwise unexplained variation in nuclear capacity factors.

[10]For example, cases in which regulators have already ruled that the performance was low due to imprudence.

[11]If the utility's cost recovery is determined by the target, rather than by actual performance, then the target should be used in subsequent computations.

[12]A capacity factor of 210 per cent might be required, or a heat rate of 3,000 Btus per kilowatt-hour.

ered, and the break-even standard would finally become obsolete. At that point, a comparative standard could be substituted.

If the utility should determine at some point that the benefits of a plant are unlikely to catch up with its costs, it can ask its regulators for explicit treatment of the difference, just as it would for any other large investment which must be written off. In this situation, it would be crucial that the utility be absolutely candid regarding the costs and benefits of the plant, in order accurately to assess the size of the net loss. The regulator would then have to determine what portion of the total cost of the plant should be recovered over its life. This fraction may range from 100 per cent of the costs down to the portion of costs justified by the savings, or perhaps some lower figure.[13] Once that fraction is determined, a multiplier can be calculated, so that applying the break-even standard with the multiplier over the anticipated life of the plant will recover those costs which the commission has approved. The multiplier may be applied to the fuel savings factor, to the cost of the displaced fossil fuel, to capacity cost savings, or to total savings. The choice of the application of the multiplier should depend on the regulators' perceptions of why the plant will not pay,[14] why its completion was justified,[15] and what costs the plant represents the best insurance against.[16]

[13]The extent of the savings seems to me to be the lower limit for cost recovery, so long as the utility's errors are confined to decisions to continue construction after that became imprudent. If the regulator finds that the plant should have been completed, but that competent management would have brought it into service for a much lower cost, then cost recovery may reasonably be limited to the cost of completing the plant prudently.

[14]For example, if the principal problem is that capacity factor projections were too high, the multiplier might be applied to all fuel savings.

[15]If decisions to continue construction were reasonable because of concern that resurgent demand would otherwise require enormous efforts to catch up in installed capacity, the multiplier might be applied to the avoided capacity costs.

[16]For example, a nuclear unit would provide some insurance against future coal price increases (from acid rain legislation, perhaps), in which case perhaps the excess costs are most appropriately recovered from a surcharge on avoided coal prices.

Training Programs Offered by Major Engineering and Construction Firm

Bechtel Power Corporation last year logged more than 130,000 hours of power plant operator and maintenance personnel training at Bechtel projects. This year, for the first time, it is offering its extensive training resources to all electric utilities. Bechtel currently offers more than 1,300 operations and maintenance training courses.

Bechtel's training programs in many instances meet accreditation subject matter requirements established by the Institute of Nuclear Power Operations for training of maintenance and technical personnel at nuclear power plant facilities. Utilities will have the opportunity to adapt existing training courses rather than undertake the expensive and time consuming task of developing their own programs.

"It has become increasingly apparent that high quality training is the key to successful operation of modern power systems," says Lou Peoples, manager of planning and plant operations at Bechtel.

The company has instituted successful training programs at a wide variety of facilities around the world. Among the successful Bechtel programs, one in Spain graduated more than 2,000 technical, professional, and field nonmanual employees from training programs at five nuclear facilities. As part of the design and construction of a large petrochemical complex in Puerto Rico, Bechtel graduated more than 6,000 trainees in various craft specialties. In Papua, New Guinea, Bechtel prepared all courses and carried out on-the-job training for the plant operating and maintenance staff of a three-unit, oil-fired steam generating unit.

Bechtel has carried out many successful training programs at power plants in the U. S. Included in Bechtel's training program are courses in technical support and management, cost-effectiveness, quality control, radwaste handling, security, and start-up. More information about the 1,300 Bechtel courses can be obtained from Lou Peoples, Bechtel Power Corporation, P. O. Box 3965, San Francisco, California 94119.